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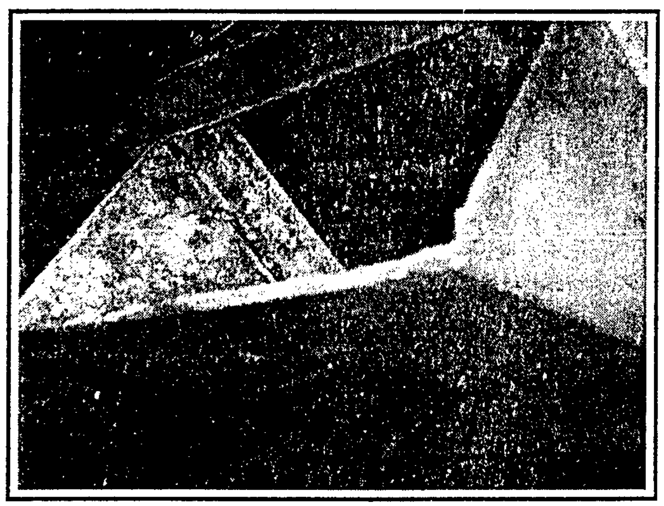
Technical Assistance To Supplement Installation of Low NOx Boilers at the Pentagon Heating and Refrigeration Plant

Michael K. Brewer, Charles M. Schmidt, A. Henry Studebaker, Mark Coleman, Chip Matheson, James Jordon, Michael A. Caponegro, Tony Blacker, and Andrew Suby



After new Low NOx boilers were installed at the Pentagon Heating and Refrigeration Plant (PHRP), the U.S. Army Construction Engineering Research Laboratory (CERL) was tasked by the Baltimore District Pentagon Renewal Office (PRO) to research several issues related to the installation and performance of the units. CERL assembled a team of engineers to conduct on-site testing and inspection to assess whether the installed system met the intent of "parallel metered combustion controls" to produce safe and stable low NOx combustion. The team made four site visits to investigate the adequacy and safety of the primary air and flue gas recirculation configuration with regard to combustion control, to address items of special interest to the PHRP, and to make recommendations to improve system performance.

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13. ABSTRACT ***(Maximum 200 words)***

After new Low NOx boilers were installed at the Pentagon Heating and Refrigeration Plant (PHRP), the U.S. Army Construction Engineering Research Laboratory (CERL) was tasked by the Baltimore District Pentagon Renewal Office (PRO) to research several issues related to the installation and performance of the units. CERL assembled a team of engineers to conduct on-site testing and inspection to assess whether the installed system met the intent of "parallel metered combustion controls" to produce safe and stable low NOx combustion. The team made four site visits to investigate the adequacy and safety of the primary air and flue gas recirculation configuration with regard to combustion control, to address items of special interest to the PHRP, and to make recommendations to improve system performance.

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Foreword

This study was conducted for U.S. Army Corps of Engineers (USACE), Baltimore District, Pentagon Renovation Office, under Military Interdepartmental Purchase Request (MIPR) No. E85-97-W1-99, "Technical Support To Evaluate the Low NOx Boilers at the Pentagon Heating and Refrigeration Plant (PHRP)." The technical monitor was Tim Gordon, CEMP-ET.

The work was performed by the Energy Branch (CF-E), of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). Baltimore District Points of Contact at the time of this study were: LCDR Rob Fetter, Dave Westrick, and Jim Wang. The CERL Principal Investigator was Michael K. Brewer. Larry M. Windingland is Chief, CECER-CF-E and Dr. L. Michael Golish is Chief, CECER-CF. The technical editor was William J. Wolfe, Information Technology Laboratory.

The Director of CERL is Dr. Michael J. O'Connor.

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Background

After new Low NOx boilers were installed at the Pentagon Heating and Refrigeration Plant (PHRP), the U.S. Army Construction Engineering Research Laboratory (CERL) was tasked by the Baltimore District Pentagon Renewal Office (PRO) to research several issues related to the installation and performance of the units over the course of four site visits. The first three site visits conducted in calendar year 1997 (CY97) were to investigate the adequacy and safety of the primary air and flue gas recirculation configuration with regard to combustion control. The fourth site visit in November 1998 was to address some items of special interest to the PHRP.

In response to phone calls from Don Kuney, Rob Fetter, and Dave Westrick during the time period 15 to 18 April 1997, CERL conducted a review of faxed material, military standards, and National Fire Protection Association (NFPA) standards. CERL also consulted with Schmidt and Associates (SAI), Cleveland, OH, and set up a three-way phone conference between PRO, SAI, and CERL. CERL was originally asked if a judgment could be made over phone as to whether the mechanical linkage on the damper controls was safe and adequate to meet the requirement of a "parallel metering control system with oxygen compensation control."

Based on the preliminary information, CERL and SAI concluded that the control design specified in FD-1 and FD-2 is satisfactory and more than adequate to control a 40,000 pph boiler. However, the information describing the installed equipment as faxed by PRO did not appear to meet the intent of the specification and design for "parallel metered control." Only the fuel system appeared to be metered. The differential pressure (DP) from the forced draft (FD) fan to the windbox pressure is not metered combustion airflow. It appeared to provide a relative airflow signal. Whether the installed system is "safe and adequate" could not be determined over the phone.

The design objective for the boilers was based on the specification of "parallel metered control" as described in (military specifications) MIL-B-18796F (12 July

1990) and MIL-A-17095H (20 August 1990), which describe three typical types of boiler controls. MIL-A-17095H states that:

> 3.15.1 Burner combustion control system. The burner combustion control system shall be in accordance with MIL-B-18796. When specified (see 6.1.1 and 6.2), the combustion control system shall be furnished with an oxygen compensation system, or when specified (see 6.2), an oxygen compensation system with an unburned combustible gas analyzer. The combustion control system shall be one of the following, as specified (see 6.2):
>
> a. Single point-positioning control.
> b. Parallel positioning control.
> c. Metering control.

Parallel positioning requires the control for the air and fuel be separate so that the air can lead the fuel on increase fire and fuel can lead air on decrease fire. The separate positioners will also allow the installer to optimize the fuel-to-air ratios over the span of 25 to 100 percent load. Metered control requires air and fuel measuring devices (orifice plates, flow venturi ring) as a control input. As described in the faxes, the FD fan to windbox DP was used as the combustion air signal for the combustion controls. Whether this DP is adequate, useful, or detrimental as a control input could not be determined.

PRO, CERL, and SAI discussed the Applicability of NFPA guidance on Low Nox Boilers. In NFPA 8501, *Standard for Single Burner Operation*, Appendix A, Section A-2-7, subsection (c) "Low-Nox Operation — Special Problems," and subsection (d), "Hazards of Low Nox Firing Methods," the non-binding section of the standard states:

> (d). Hazards of Low NOx Firing Methods.
>
> 1. (c) When flue gas recirculation is used, equipment should be provided to assure proper mixing and uniform distribution of recirculated gas and combustion air. When flue gas recirculation is introduced in the total combustion air stream, equipment should be provided to monitor either the ratio of flue gas to air or oxygen content of the mixture. When flue gas recirculation is introduced so that only air and not the mixture is introduced at the burner, proper provision should be made to ensure the prescribed distribution of air and the recirculation glue gas/air mixture.

Two concerns were raised about the installed boilers. The first issue was how the installed windbox was able to achieve proper mixing and uniform distribution of recirculated flue gas and combustion air. The current windbox brings combustion air and flue gas to the windbox through separate ducts and dampers

(Figure 1). The second issue was whether the dual duct work and dual dampers meet the intent of monitoring the ratio of flue gas to air since the oxygen content of the mixture is not measured.

The information originally provided was not sufficient to allow CERL researchers to offer an opinion on whether the flue gas was thoroughly mixed in the windbox and burner. It is difficult to get thorough mixing by introducing flue gas separately in the windbox. Flue gas is usually introduced upstream of the FD fan so that the combustion air and flue gas are thoroughly mixed. If flue gas is introduced in the burner or windbox, ductwork and fittings are used to uniformly introduce flue gas in or near the burner throat. As described in NFPA 8501, properly constructed Low NOx burners already have a decreased operating margin before encountering unstable flames or producing high levels of unburned combustibles in the furnace and ductwork. If unmixed flue gas reaches the burner, the margin is decreased even further.

At the request of PRO, CERL assembled a team of engineers from CERL, the Naval Facilities Engineering Support Center (NFESC) and SAI. Black and Veatch, Inc. (the project design engineers) also participated in the evaluation team. The team conducted testing and inspection to assess whether the installed system meets the intent of "parallel metered combustion controls" and can produce safe and stable low NOx combustion.

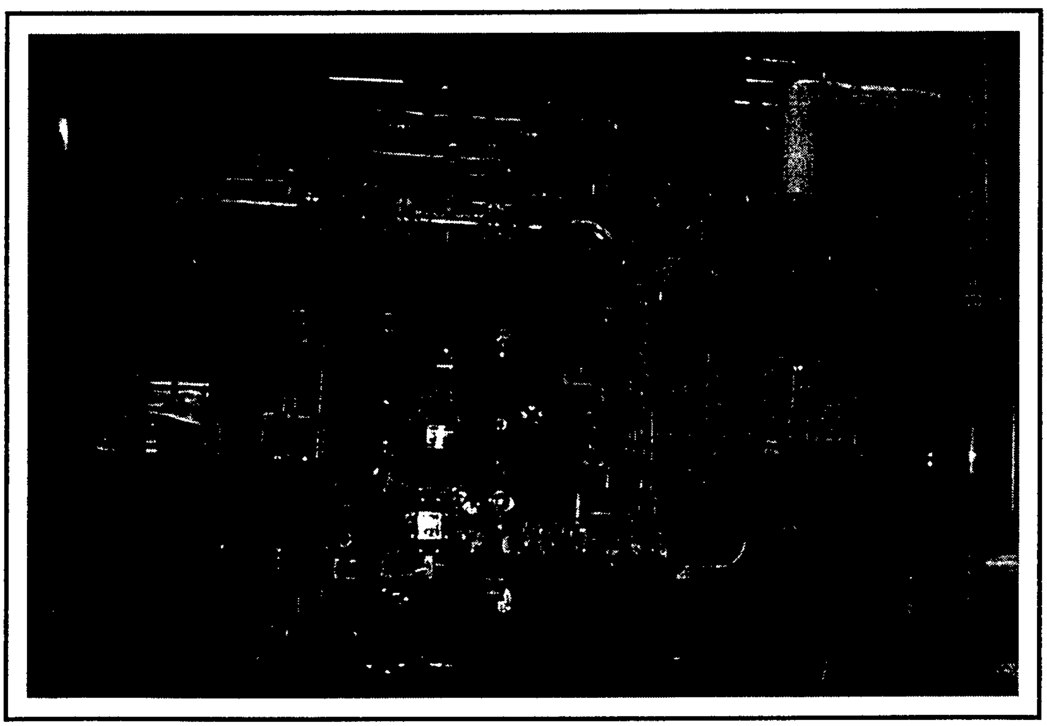


Figure 1. Front of windbox.

Objectives

This objective of this project was to analyze the Low NOx burners installed at PHRP for safety and adequacy, and to provide other technical support as needed by PRO and PHRP.

Approach

Initial technical assistance encompassed several tasks. The first site visit included three tasks:

1. *Current System Inspection and Testing*. The team reviewed drawings and diagrams, tested and inspected one on-line and one off-line boiler, and conducted a 1-½ day site visit to collect data on the safety and adequacy of the low NOx burner system.

2. *Letter Report*. Based on the information gathered, a letter report was drafted describing the findings and listing remediation recommendations.

3. *Present Findings*. The results were formally presented to the sponsors.

After the first site visit the sponsor amended the tasks to increase the scope of work to include the following tasks:

4. *Continue System Technical Review*. The team reviewed shop drawings and diagrams, participated in telephonic and on-site review meetings, and researched the current system and potential modifications to the burner and boiler.

5. *Commissioning Support*. CERL organized a team to support commissioning for one boiler as directed by PRO, develop and/or review test protocols, and analyze commissioning test data. The team of engineers assembled to participate in several days of testing on a boiler. NFESC, CERL, and CERL contractors were engaged to provide team support. A follow-up site visit was made to close out the commissioning data analysis and to assist in other matters as directed by PRO.

6. *Summary Report*. A summary report was authored to document results of the technical support effort.

After the commissioning, the PRO and PHRP requested the following additional assistance to close out the project:

7. *O_2 System Technical Review*. Plans to move the O_2 sensor from its location high in the ceiling to the boiler outlet were reviewed. Moving the sensor promised to improve the sensor's accuracy because the long run of ducting with its joints allowed ambient air to infiltrate the flue gas. Locating the sensor near the operating floor would greatly improve the quality and frequency of maintenance the sensor could receive. After the PHRP implemented the plan, the team returned to test and trim the controls on the boiler.

8. *Boiler Inspection*. After the O_2 sensor move had been tested, the team inspected and tested additional boilers.

9. *Consult on Boiler Blowdown Regulator*. The boiler feedpump bypass orifice was investigated. The results of Tasks 7, 8 and 9 were included in the summary letter report (Task 6).

Mode of Technology Transfer

Lessons learned from this project will be transmitted directly to PRO. After the plant construction has been completed, a summary of important lessons will also be transmitted to PRO, CEMP-ET, and ACSIM for recommended inclusion in guide specifications and technical notes.

2 Site Visit 7-8 May 1997

Pre-Testing Meeting

A meeting was held the afternoon of 7 May 1997 in the PHRP conference room. The meeting minutes were produced by PRO and the project A/E. Several issues related to the boiler controls and flue gas recirculations were discussed.

Atomizing Steam

Steam piping work has been done to reduce the likelihood of water being present in the steam oil atomization system. The steam for the oil atomization system has a long run from a common steam header. Many boilers use steam from the drum to access dry steam.

Windbox Stratification

The current windbox was suspected of having unmixed flue gas and combustion air entering the boiler. The installer contended that there was no unmixed flue gas and air in the windbox, and even if there were, it would be of no consequence to the operation of the boiler. The assistance team did not agree with this contention.

Boiler Controls

It appears that not all of the documentation was available for the project A/E and PRO to thoroughly examine the boiler controls as installed. The suitability of the DP from the FD fan to windbox as the combustion air signal was discussed at length. The installer contended that it was adequate. The team acknowledged that it would indicate some sort of relative airflow. However, there was concern that the signal may be noisy as the current control algorithms apply a lot of averaging and filtering to the signal. There was also concern about carbon monoxide (CO) spikes seen during up and down power transients. Another concern was how the system responded to a step function, which could be introduced by a short loss of communications from the sensors to the controllers.

Sensors

The span available on the Bristol Babcock sensors was discussed. The smallest span available for the smart sensors is +100 in WC to -100 in WC. The PHRP was concerned that, for small DP signals, the sensor may not be accurate enough. The project A/E and the installer seemed to agree that the accuracy of the sensor, even when scaled down, met the specified tolerances.

Plant Tour

The team took a short tour of the plant before testing. The overall plant layout was very spacious and included ample space to improve maintainability.

Boiler #5 Furnace Inspection

The installer opened up the windbox and furnace on Boiler #5. The windbox and burner are simple in construction. There are no vanes or baffles to ensure thorough mixing of the flue gas prior to entry to the burner throat. Corrosion had already begun to occur where the flue gas entered the windbox (Figure 2). The burner has one set of flat register vanes (Figure 3). The tubes in the windbox did not show any signs of flame impingement although boiler #5 did not have many hours of operation. The laydown chalk makings were still visible. The soot pattern from burning oil can be seen on the left furnace wall (Figure 4).

Boiler #3 Windbox Testing

The team sampled the combustion air and flue gas mixture at four positions around the entrance to the burner register. They removed one bolt at a time from the front of the burner to insert a K type thermocouple and gas analyzer probe (Figure 5). The sampling was done at low fire, 50 percent steam load, and 100 percent steam load on oil and gas. Sample results indicated that the flue gas and combustion air were not thoroughly mixed entering the burner (Figures 6 and 7). The gas flame was observed to have colder and hotter quadrants. At 50 percent load, the top half was much hotter as indicated by the glowing refractory. At 100 percent load, the hot quadrant rotated clockwise (as viewed from the rear of the boiler) about 90 to 140 degrees. Thermocouple data confirmed that the oxygen-rich quadrants are near the top at 50 percent load and shift at least one quadrant during 100 percent load (Figure 8). The gas flame is affected by the unmixed air supply stream at all loads. The lower portions of the flame front are pulled down and out of shape.

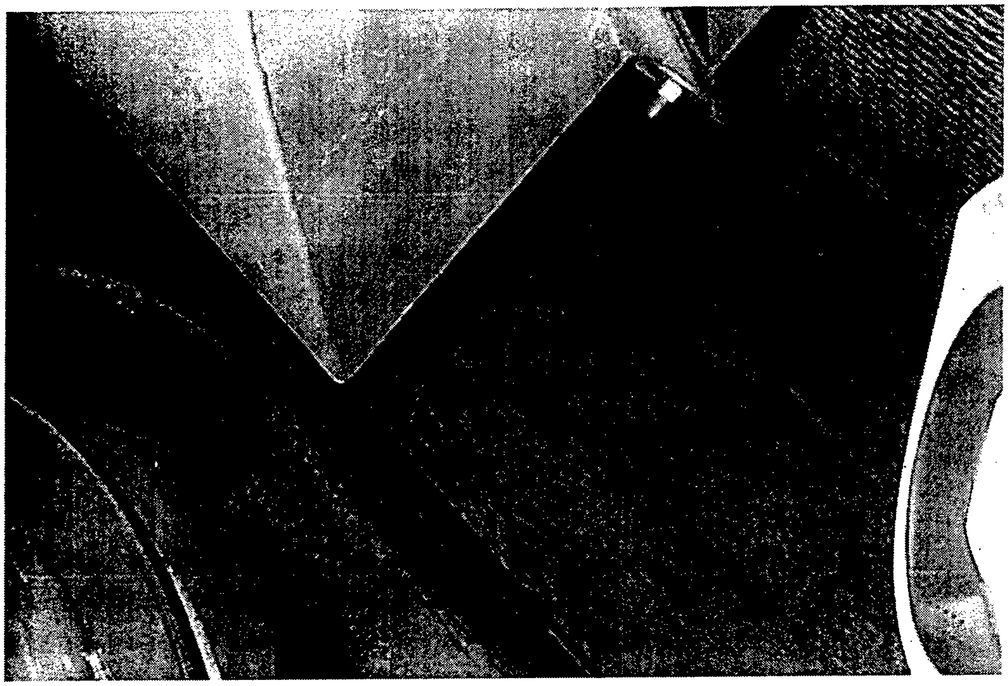


Figure 2. Windbox corrosion.

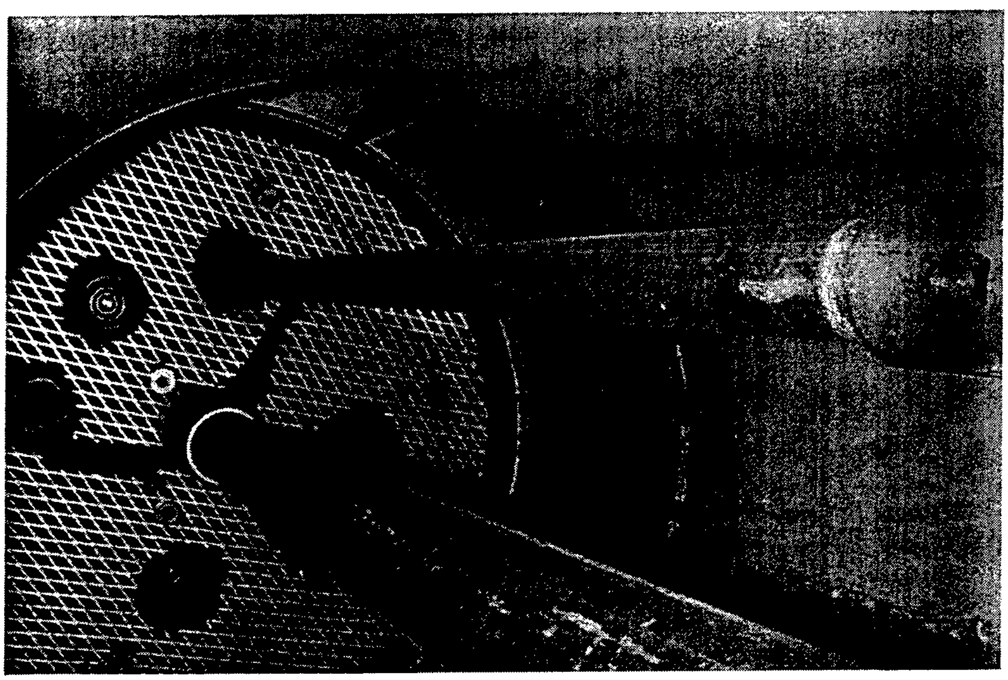


Figure 3. Burner register.

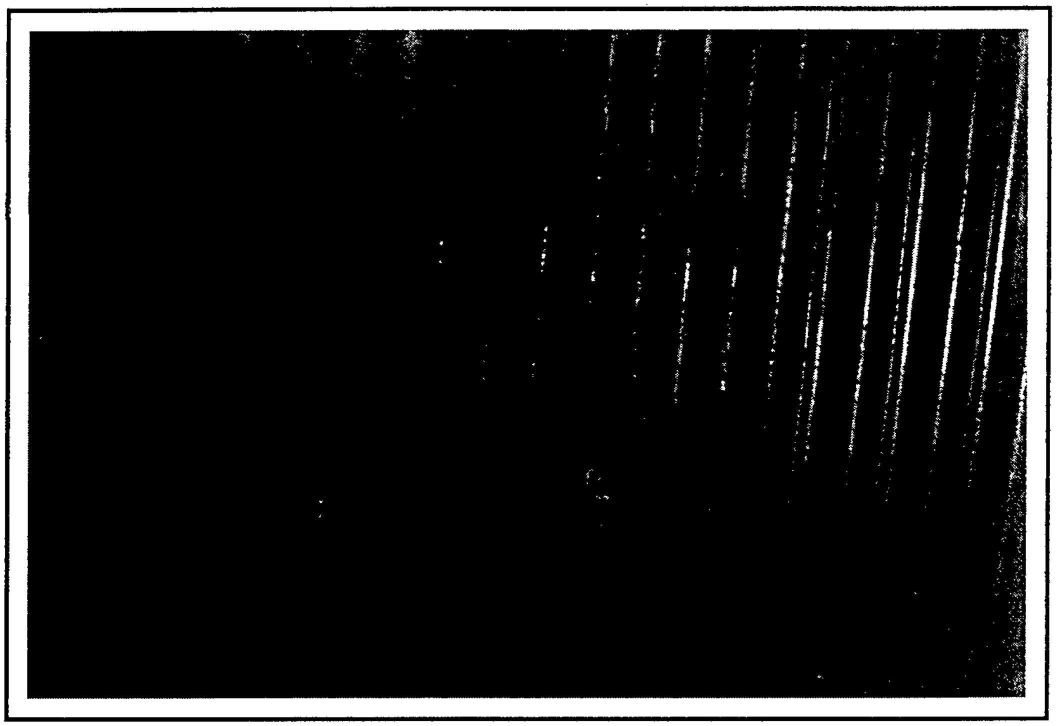


Figure 4. Left furnace wall.

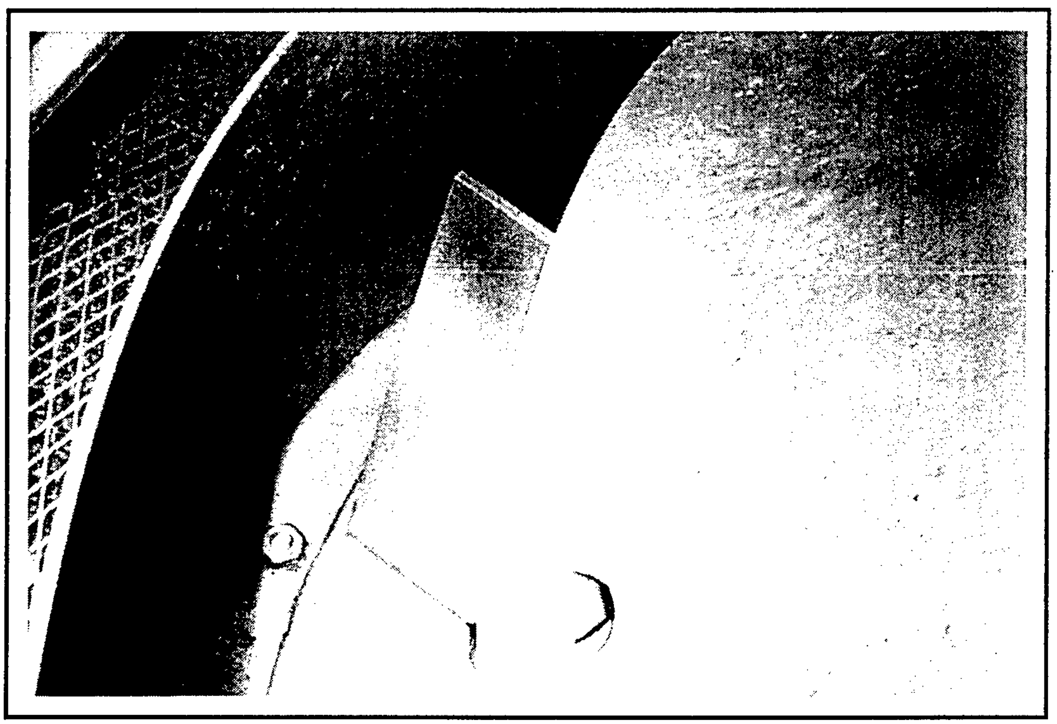


Figure 5. Windbox sample point.

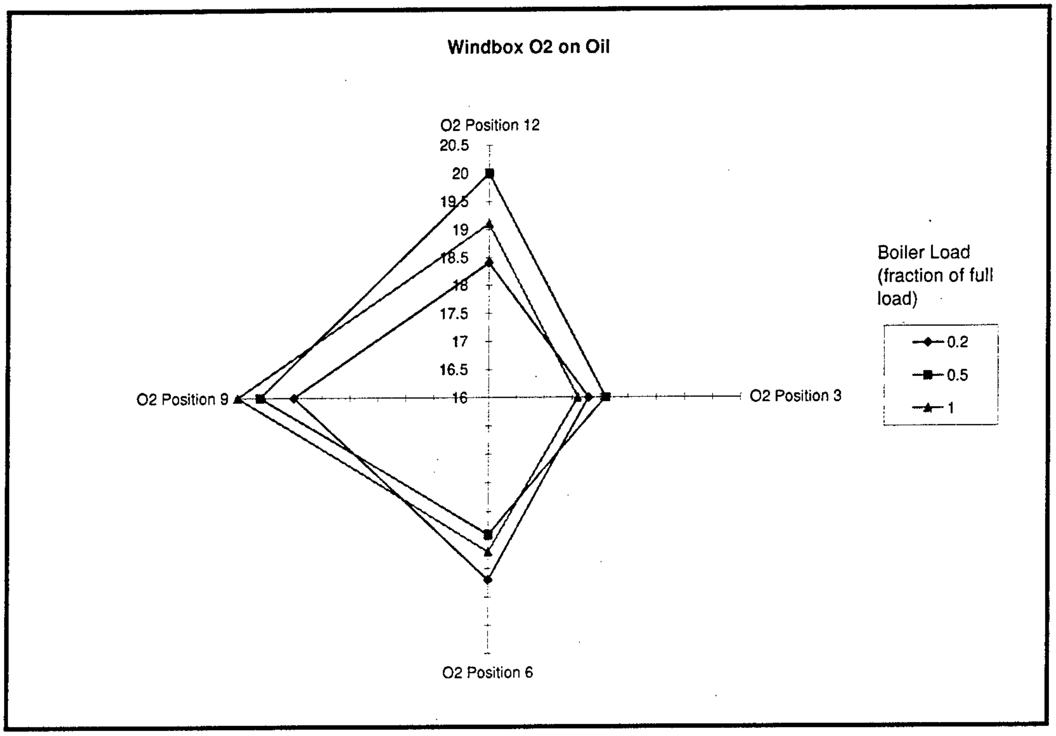


Figure 6. Windbox oxygen concentration at three loads.

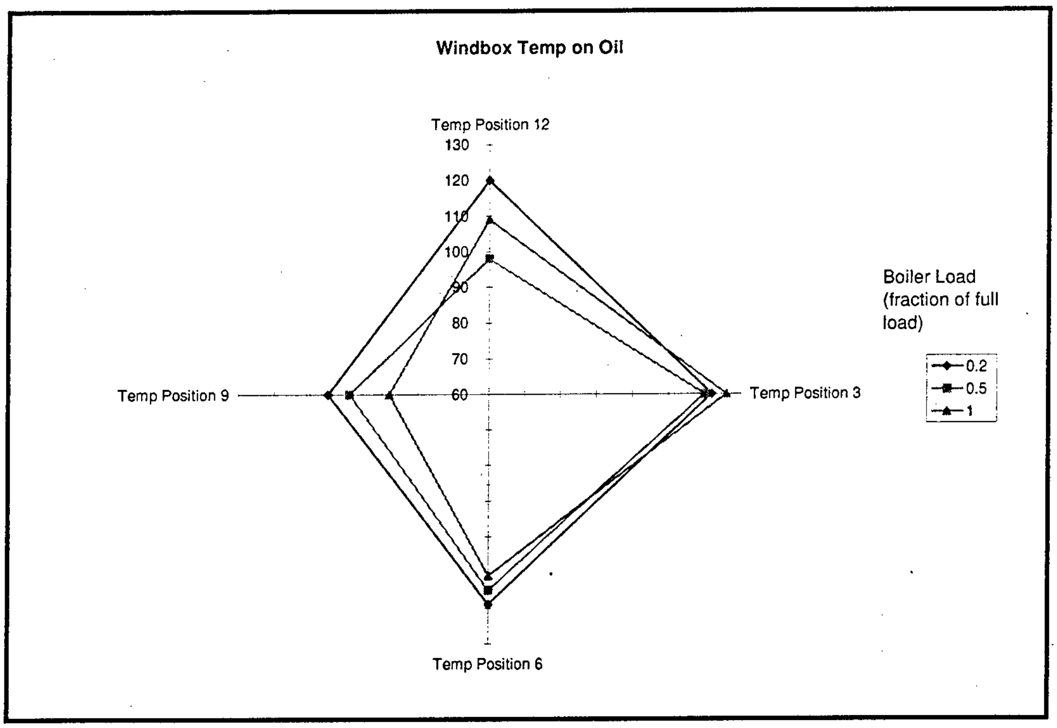


Figure 7. Windbox temperature at three loads.

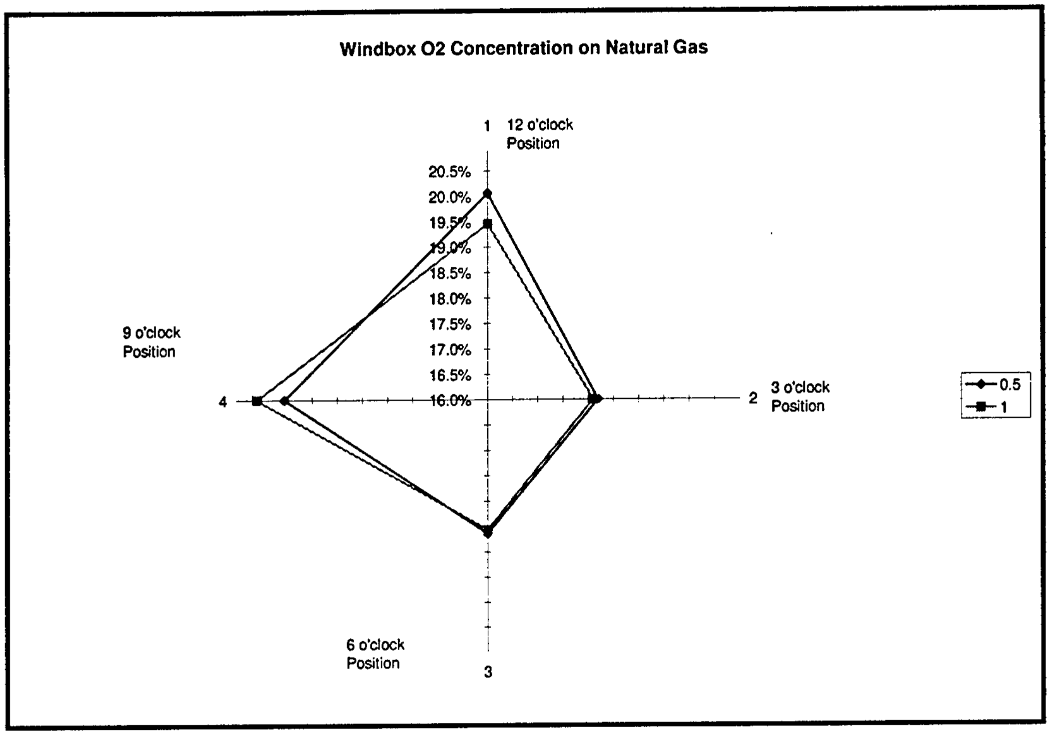


Figure 8. Windbox oxygen concentration on natural gas.

On oil with a properly operating oil gun, the flame front was uniform and well shaped at 50 percent load and higher. At loads below 50 percent, the flame was brighter near the top half and colder in the bottom half. This was probably due to the higher oxygen content in the air at the top of the burner and less turbulent conditions.

The windbox flue gas and air stratification is probably more detrimental to the natural gas as the gas flame shape is a function of how the gas diffuses into the combustion air stream. However, the oil flame shape is more of a function of the atomization pattern from the oil gun. At higher firing rates with increased turbulence, the stratification effects are further reduced for oil.

Several burner manufacturers rely on dual registers and induced flue gas recirculation performance to avoid stratification in the burner.

Boiler #3 Operational Testing

Boiler flues were also sampled during the windbox testing. The installed oxygen sensor (wet analysis) seemed to be reading about 1 to 2 percent higher than normal during the later portions of the testing. Some of the difference (about 0.4 percent on oil, 0.6 percent on gas) will be due to moisture as the test equipment

uses a dry sample and the installed sensor does a wet analysis. The data is not comprehensive over all periods of operation because the original test plan did not focus on O_2 sensor alignment. The installer's boiler operator also noticed the boiler controls seemed to overtrim the oxygen in the early portions of the testing so he removed the O_2 trim signal. The feedwater flowmeter was out of alignment as it always read 22,000 to 29,000 pounds per hour feedwater flow at all loads.

Near the end of the testing session, the air flow transmitter lost communications with the controller. The installer determined the cause was a poorly connected data cable.

There was a major CO excursion (over 3900 ppm) when the boiler master controller was in manual control mode on oil and raising the load. The airflow signal had been lost and the controller was using the last known value. This allowed the operator to bring fuel up and create a fuel rich condition.

It took several iterations to get a stable oil flame. The oil gun had to be cleaned several times before a good flame pattern was achieved. The source of the fouled oil gun could have been due to poor storage practices. There was concern that some of the debris from the steam trap work on the steam atomization lines could have fouled the burner. However, no material could be seen left in the oil gun.

The airflow signal had large fluctuations (20 to 40 percent) when the dirty oil gun was causing poor combustion. Pulsations from the furnace area were being sensed in the windbox. However, as long as a stable flame was present, air signal was also stable.

Summary of 7-9 May 1998 Recommendations

Based on the boiler's performance during the site visit, the team was not prepared to declare that the burner and combustion controls were safe and adequate to operate at all loads, for all specified fuels, and during transients. Although a stable flame was observed at some steady state conditions, unstable flame patterns and unexpected carbon monoxide excursions were also observed. There is limited experience with unmixed forced flue gas recirculation to the windbox. The team recommended that, if the boilers were allowed to continue to operate, utmost diligence and caution needed to be exercised. To provide an extra measure of safety, the team recommended that, to reduce the probability of uncontrolled CO or combustible gas excursions, the boilers be operated with at least the following precautions:

- Program the boiler to trip on high CO (> 400 ppm). This trip may need to be cut out until the flame is proven during startup to allow for ignition transients. The CO and oxygen sensors will need to be calibrated frequently. The team initially recommends a daily calibration of both sensors. If the sensor accuracy proves to be repeatable for a week, the calibration frequency can be reduced. No new sensors should be needed as schematic FD-1 shows that the CO and oxygen sensors currently provide input to the burner controls. Additionally, the team was told during the site visit that fittings are installed or will be installed to conduct daily calibration of the oxygen sensor.
- Program the boiler to trip on low oxygen (< 1.5 percent).
- If a high CO and combustible condition occurs (the annuciator is to alarm at 400 ppm) and the boiler does not trip itself, the boiler should be manually tripped to avoid further evolution of combustible gases.
- Implementing these trips is not desirable for a long-term fix. Their purpose is to provide a margin of safety from a high CO or combustible condition until the burner configuration and boiler controls can be investigated.

The following observations formed the basis of the team's opinion:

- Combustion air and recirculated flue gas are stratified in the windbox contrary to NFPA 8501 (85A) guidance. This contributed to poorly formed flames on natural gas at all loads and on oil at loads of 50 percent and below.
- The combustion air to flue gas ratio is not monitored, nor is the O_2 in the windbox measured, contrary to NFPA 8501 (85A).
- The full parallel metering control, as specified, is usually applied to larger boilers (> 100,000 pounds per hour). The increased complexity of the controls geometrically expands the potential sources of faults and trips. Full parallel metering control demands a robust commissioning program and an on-going maintenance program to verify proper performance across a wide range of conditions. This increased fault potential has already been evident for these boilers during startup, testing, and during the team's site visit.
- The combustion air signal is a relative air signal and is very noisy under certain conditions. Pulsation in the furnace due to poor combustion is sensed by the high side of the combustion air transducer. Oscillations of 20 to 40 percent of the measured values were observed. The oscillations were observed to be absent above 50 percent load.
- Corrosion is already present in the windbox where the flue gas enters. The corrosion will shorten the life of the windbox equipment. Condensation of moisture in the windbox is not observed with induced flue gas recirculation burners. Although the boilers were specified to be able to burn #6 oil, such

sulfur-bearing fuels cannot be burned unless the burner and windbox is fabricated out of 316L stainless steel.

The team observed other conditions at the plant that should be addressed to successfully commission the PHRP.

- The materials selected for the windbox and burner will not permit using #6 oil at any time (to avoid accelerated windbox and burner corrosion from sulfuric acid). Presently the PHRP air quality permit does not allow using #6 oil. However, oil heaters were installed to accommodate firing #6 in the future. Additionally, #2 oil with excess sulfur should not be burned for the same reason.
- Many flue gas recirculation burners have a different flue gas to air ratio settings for oil and natural gas. The team did not find any accommodation for changing the ratio of flue gas to combustion air when switching fuels.
- Some of the sensors were out of alignment. A sensor calibration program should be initiated.
- Fuel oil burner operation and maintenance procedures need to be improved. The oil guns were not ready to fire. The training and tools need to be in place so that the operators can switch to oil efficiently should a gas curtailment occur.

The team identified some options to address the problems observed:

- If the air permit limits will allow, operate the boilers without the recirculated flue gas. Simplify the controls to parallel positioning with O_2 trim. This will require testing of the boiler to verify that the burner meets emission limits without recirculated flue gas. If the NOx performance of the burner is good enough, this is the simplest solution.
- Install a new FD fan, (if necessary) install a new induced flue gas burner, and simplify the controls by going to parallel positioning. Burn only gas and low-sulfur fuel oils.
- If the capability to burn #6 fuel oil must be maintained, install a new FD flue gas burner and or fan. The components in contact with the flue gas need to be fabricated out of 316L stainless steel. This is the most expensive option and only has merit if the #6 oil option must be maintained.
- Significantly modify the existing windbox to get rid of stratification, change the air flow sensor or sensing point, and test the modified system for all the trips with single component failures. This approach may be costly in effort and time for the first unit. Modeling and test trials will be involved to see if

the modifications are effective. Additionally, the changes may still require replacement or rework of the FD fan. Burn only gas and low-sulfur fuel oils.

- Keep the existing windbox and burner, remove the flue gas recirculation fan and existing recirculation ductwork, install a new FD fan, and (if necessary) FD fan dampers and ductwork to implement induced flue gas recirculation. Simplify the controls to parallel positioning. Burn only gas and low-sulfur fuel oils.

The team recommended the first option since it requires the least rework. If the NOx performance of the existing burner without flue gas recirculation is poor, the team recommends the fifth option since it requires the least design and construction uncertainty and uses the existing windbox.

Results of Site Visit

After receiving the team's recommendation, the PRO notified the installer of the team's conclusions. The installer then shut the boilers down instead of operating them in a restricted condition. The installer was given the opportunity to address the problems observed by the team. The team was invited back to observe another set of tests to establish confidence in the safety and adequacy of the low NOx burners.

3 Site Visit 17-19 June 1997

A team of engineers assembled by CERL conducted a site visit to PHRP 17-19 June 1997. The team consisted of Charles M. Schmidt (SAI), A. Henry Studebaker and James A. Jordon (NFESC), and Michael K. Brewer (CERL). The team met with PRO and PHRP personnel.

At the meeting, the following topics were briefly discussed:

- Boilers should be tuned to operate at less than 100 ppm CO. As control of combustion is lost, the CO concentration increases exponentially above 200 PPM.
- The current air quality permit for NOx is 0.06 lb/MBTU heat input (49.6 PPM at 3 percent O_2) for natural gas and 0.08 lb/MBTU heat input (62.5 PPM at 3 percent O_2) #2 oil.
- The ASME 4.1 test done by the contractor was done in manual control mode. Nine of 16 runs were performed more than 9 psig below rated pressure (116 psig instead of 120 psig). The PRO AE consultant observed that, although the contractor installed a positive displacement water meter on the feedwater line, the test team used steam flow to determine boiler output. Although ASME 4.1 specifies 4-hour test runs for gas and oil fuels, it is not clear if the departure from ASME 4.1 was agreed upon by all parties.
- The PHRP personnel indicated they could operate if the boiler load rate change was limited to 10 percent of maximum continuous rating (MCR) per minute.
- NFESC uses the MO 324 to test boilers. The team will review MO 324 to ascertain which portions may be useful for the PHRP boiler test. NFESC also has a week long procedure to tune and test boilers.
- The feedwater control was specified to use three elements, but currently uses two elements.
- The team discussed the merits of slowing down the control system response (increased system time constant).
- The team discussed the merits of reducing or eliminating flue gas recirculation. PHRP environment staff was going to inquire of the state air quality authorities if the current limits can be raised without having to install con-

tinuous monitoring systems (CMS). Emission rates of the old boilers should help justify higher and more reasonable limits.

Two main issues concerned the team. The first issue is whether the burner will deliver the required performance and that the burner management system will operate correctly. The second issue is whether the current boiler controls are installed, programmed, and tuned to perform reliably and safely under all fuels, loads, and transients.

The team then toured the plant. The team noticed that the shutdown plant indication was inconsistent. The team discussed the merits of working on one boiler to eliminate the issues preventing acceptance. The team proposed the ground rules for the boiler commissioning regarding:

1. *Manual Operation.* The team would conduct an eight-point test run on each fuel as follows: (a) no O_2 trim, (b) limited CO to less than 100 PPM, (c) limited NOx to permit requirements, and (d) limited O_2. Charles Schmidt proposed the following combustion test limits:

Boiler Load	O_2 (Natural Gas)	O_2 (#2 Oil)
17-25%	5%	6%
25-40%	3.5%	4.0%
40-100%	3%	3.5%

2. *Automatic Operation.* The team would: (a) allow steam header pressure swings of +/- 2-3 psig so the system would not be so active, (b) slow down reset signal to once every 20 seconds, (c) reduce gain integral to a 5 percent slope, (d) on load changes, always maintain air-rich conditions, (e) limit O_2 trim effect to less the +/- 0.5 percent, and (f) test for combustion performance the same as with manual operation.

3. *Burner Management.* The team would be allowed to test failures of primary elements such as fuel valve position elements, loss of communications, and loss of sensors to verify that the fuel valve will close, or that, if fuel stays in position, air stays in position (no fuel-rich event). The team would be allowed to develop a plan of action to get one boiler commissioned. Naval Facilities Engineering Command Maintenance and Operations Manual (NAVFAC MO) 32, *Inspection and Certification of Boilers and Unfired Pressure Vessels* (March 1992) was suggested as good template for the plan. The team would complete digital control systems (DCS) to primary element calibration and alignment. Once all the sensing lines are cleaned out, the contractor will

finish verifying that the digital signal and 4-20 mA carrier signal is aligned with the primary sensing elements.

4. *Test Burner Management.* The team would test that all NFPA protective functions operate from the primary sensing element. If a test item were already performed, the test data would be provided for review for completeness. The goal is to eliminate any problems attributed to poor burner management. Of particular concern to the team was a full or partial failure of the FD fan while the recirculation flue gas fan is operating. The team wants to verify that loss of combustion or loss of flame trips occur to prevent a fuel rich or combustible gas condition in the furnace.

5. *Test Burner Mechanically.* The team proposes to operate the burner in manual control mode to verify that the installed burner management system, windbox, registers, burner, and furnace performs as specified without nuisances from DCS problems.

6. *Test in Automatic Control.* There will be at least three options for this test: (1) run the system as presently configured, (2) run as specified (the element feedwater control, etc.), and (3) run with a simplified controls system (parallel positioning, minimum O_2 trim). Temporary sensors and digital signal test equipment will need to be installed to verify the digital signal and the 4-20 mA carrier signal are aligned with the condition of interest (pressure, temperature, level, etc.) under a dynamic condition. The test will occur at all loads, fuels and transients. As discrepancies are discovered, the test will be suspended to allow component repair. The test will then be repeated or restarted as required. If the test cannot be completed with the current control scheme, a more simplified control scheme should be considered.

The team met with the prime contractor and PHRP staff on 19 June 1997 to discuss concerns and possible solutions. PHRP developed a list of boiler plant issues. The team developed a list of possible failures that the burner management system for a forced flue gas recirculation to the windbox system should be able to respond to safely. The two main failures of concern are an electrical failure isolated to the FD fan or failures of the belt drive system between the fan and fan motor. Linkage failure of the FD fan dampers and recirculation fan dampers seems to have a low probability. The linkage construction is adequate if the linkage receives normal maintenance and routine inspections.

If the commissioning of a single boiler is agreeable with all parties, the team proposed that the prime contractor submit a test protocol to meet the intent of the paragraphs above. The team was not able to draft a specific test protocol un-

til accurate burner management schematics are available. The test to measure the time for the burner management system to shut the fuel valve on the full or partial loss of the FD fan will need special attention. Since the FD fan and flue gas recirculation fans are not coupled, the team wants to see that sub-stoichiometric conditions are avoided, or at least that the duration of such conditions is so short that there is no potential for a furnace explosion. Initiation of a safety shutdown from the air pressure switches could be tested without having a flame in the boiler. However, if the pressure drop is not quick enough, the burner management system must rely on a fuel rich flameout. With the flue gas recirculation fan still operating, the flame may operate fuel rich too long to guarantee avoiding a hazardous condition.

4 Site Visit 21-23 July 1997

A team of engineers assembled by CERL conducted a site visit to PHRP 21-23 July 1997. The team consisted of Charles M. Schmidt (SAI), A. Henry Studebaker and Mark Coleman (NFESC), Andy Suby (Iowa State University), and Michael K. Brewer (CERL).

Based on the testing, the team found that boiler No. 4 burner and combustion controls are safe and adequate to operate at all loads on natural gas and number 2 fuel oil. The boiler operated satisfactorily in manual control mode and automatic operation during the site visit. The only occurrences of unstable flame occurred on oil when the boiler load was below an acceptable low fire point and when the burner tip had been partially plugged due to damaged o-rings. It is unreasonable to expect any industrial boiler burner to correctly operate below 6 to 1 turndown on oil. The o-ring debris was a result of damage to the rings, which probably occurred when plant personnel conducted burner gun maintenance.

During the 7-9 May 1997 testing, the team's findings were summarized into four comments in a PRO letter dated 12 June 1997. The team reviewed the summary in the PRO letter and added information to the comments as outlined below. From the PRO letter, "Combustion air and recirculated flue gas are still stratified in the windbox contrary to NFPA 8501 (85A) guidance," the applicable section of the Appendix states:

> Hazards of Low NOx Firing Methods.
>
> 1. These methods may have important implications with regard to furnace safety, particularly for existing units, and may introduce unacceptable risks if proper precautions are not taken.
>
> (a) Fuel firing systems designed to reduce NOx emissions tend to reduce the margins formerly available to prevent or minimize accumulations of unburned fuel in the furnace during combustion upsets or flameouts. Thus, it is important to trip fuel on loss of flame.
>
> (b) These methods may narrow the limits of stable flames produced by the burner system. The tests specified in 4-4.2.3 should be repeated on existing units when any of these methods are employed.
>
> (c) When flue gas recirculation is used, equipment should be provided to assure proper mixing and uniform distribution of recirculated gas and

> the combustion air. When flue gas recirculation is introduced into the total combustion air stream, equipment should be provided to monitor either the ratio of flue gas to air or the oxygen content of the mixture. When flue gas recirculation is introduced so that only air and not the mixture is introduced at the burner, proper provisions should be made to ensure the prescribed distribution of air and the recirculating flue gas/air mixture.
>
> (d) All of the methods tend to increase the possibility of an unstable flame and unburned combustibles throughout the unit and ducts; therefore, recommendations of the boiler, burner, and instrument manufacturers should be followed, or tests to verify operating margins should be conducted.
>
> 2. Any change in flame characteristics to reduce NOx emissions may require changing either or both the type and location of flame detectors on existing units.

Note that the operative wording is "should"; this section of the NFPA regarding the hazards of Low NOx burners is currently only advisory. Nevertheless, the team was not prepared to declare that the burner was safe and adequate based on the performance observed 7-9 May 1997 or on the data available for review.

The team then proposed a series of tests to help satisfy all parties involved that this unusual recirculation scheme was safe and adequate. The team also recognized that the high CO excursions could have been caused by control system communication problems. After a major portion of the control air system was cleaned and much of the DCS testing was completed, the team conducted another series of tests 21-23 July 1997. Although the flame was still asymmetrical during lower loads, the burner met the flue gas emission requirements under a variety of steady state and transient test conditions. The key criteria for an adequate low NOx burner are no flame impingement, stable flame pattern, and low NOx with concurrent low CO. The team is now prepared to declare that this configuration is safe and adequate. However, introducing flue gas to the windbox creates condensation that collects on portions of the windbox. This causes the premature onset of corrosion and material failure.

The PRO letter states that "the combustion air to flue gas ratio is not monitored, nor is the O_2 in the windbox measured, contrary to NFPA 8501 (85A)." This recommendation from NFPA is meant to prevent burner operation in a fuel rich mode due to excessive flue gas flow or diminished combustion airflow. Although the NFPA guidance is only advisory, the team did not see any information to establish confidence that all plausible failure modes were accounted for in this unusual configuration. Of major concern was the possibility that the burner would be allowed to operate in a fuel rich mode for an unacceptable length of time due

to a combustion air failure (forced draft fan) while the flue gas would continue to recirculate to the furnace. The team inspected the combustion air and flue gas linkages on the windbox and surmised that mechanical failure would be highly unlikely unless there was gross negligence on the part of the boiler operator and maintainer. However, the team was concerned that a forced draft fan drive belt failure would be a plausible failure. Most boiler fans are direct drive from the motor, which eliminates that possibility. The team wanted to test that the installed burner management system would quickly shut down the burner for a forced draft fan or fan drive belt failure. A test explained below proved that the burner management system will shut down the burner in the case of an isolated forced draft fan failure.

The PRO letter also states that "unexpected carbon monoxide excursions were witnessed 7-9 May 1997 which were possibly due to DCS communications failure." When operating above the turndown limit of 6 to 1, the burners performed satisfactorily. On 23 July 1997, when changing the steam load manually at very high rates (greater that 10 percent Max Continuous Rating [MCR] per minute), there were two CO excursions above 50 PPM when near full load followed by dropping load quickly. (Figure 9 shows the DCS printout.) It was not clear to the team why the excursions occurred under these abnormal operating conditions. Although the load change was abnormal, a parallel metered control system should have been able to handle that change. The control system did respond to the excursion appropriately and increased air to quickly reduce the CO levels. The fuel train may need closer examination to precisely identify the cause of the CO excursion. The control system characteristic curve may need adjustment. For an unknown reason at 16:40 on 23 July, the controls let the fuel valve remain fully open for 30 to 60 seconds after the airflow was being reduced. It appears that the control system ruled that the airflow was so excessive that the fuel did not need to be reduced until the airflow signal had dropped significantly. One factor may be that the fuel oil supply pressure was increased slightly to try to reach full load. The burner did perform safely under normal load transients. However, if the current airflow-metering scheme is used, the team has recommended that the control system characteristic curve be inspected and recalculated.

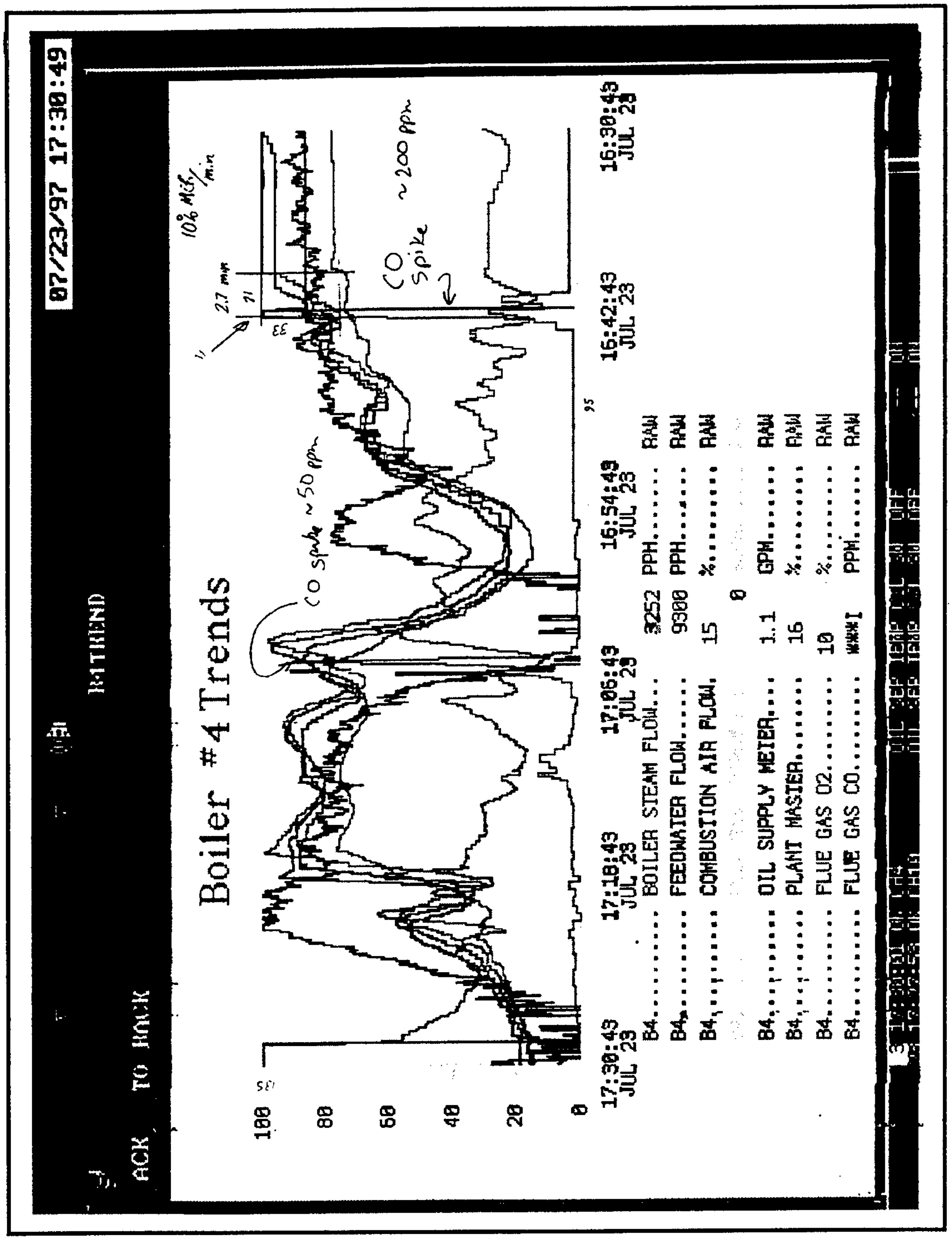


Figure 9. DCS printout showing boiler No. 4 trends.

The PRO letter further states that "the combustion air signal controlling the boilers is very noisy at low loads." To cope with that problem, the signal is averaged and filtered. This adds a time delay in the control logic. However, with a correctly operating DCS system experiencing plausible plant transients, the larger-than-normal time constant operated satisfactorily. This longer time constant on airflow may be associated with the some CO excursions seen when the boiler experiences very rapid and large load changes.

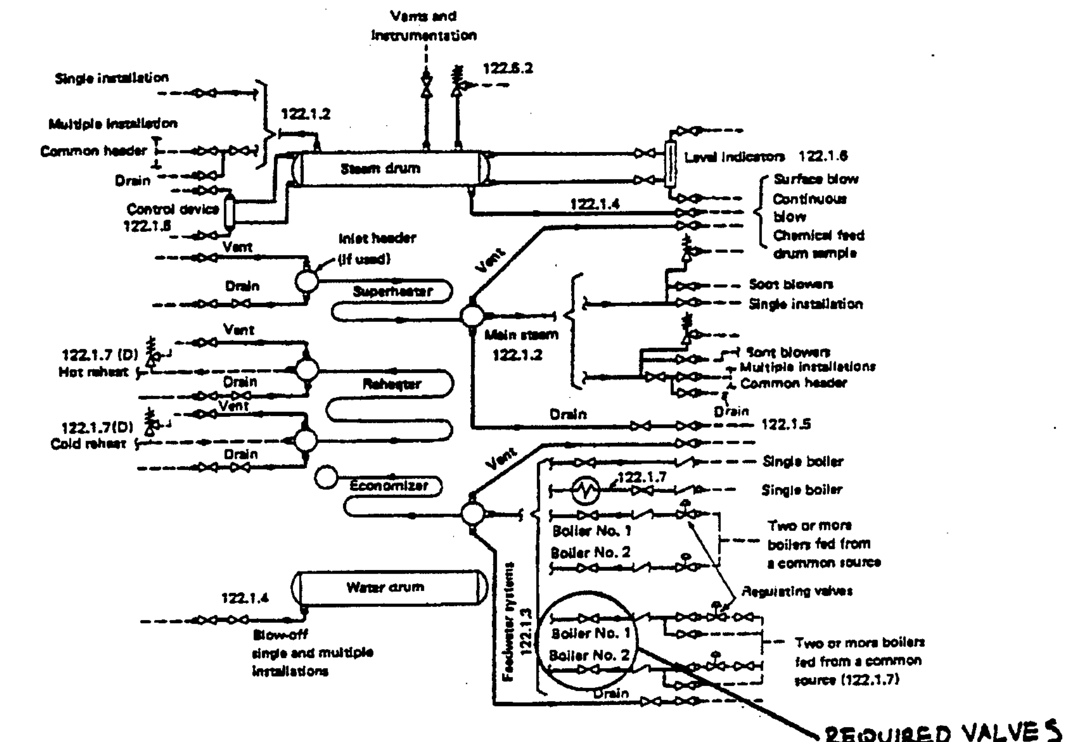
The following is a synopsis of all the observations made by the team during the 21-23 July 1997 testing:

- On gas, the boiler seemed to be limited to about 90 to 95 percent of rated capacity by the FD fan. The testing was done at worst case design conditions of lower density combustion air (85 °F). Note that the team's test did not follow American Society of Mechanical Engineers (ASME) Power Test Code (PTC) 4.1, as that was not the objective of this test. An ASME PTC 4.1 test would correctly establish the unit production rate. The team examined the available fan data. The FD fan appears to be large enough but the FD fan motor may not have enough power and speed to deliver full load air at 85 °F.*
- On gas, the emission results with manual control show that the boiler is running at higher excess air than necessary. Re-tuning the burner on gas would help mitigate the FD fan limitation.
- On oil, the boiler was limited by the fuel valve controller for the test on 22 July. The contractor adjusted the oil service line pressure and increased the load ceiling.
- All of the burner management function tests that were requested to be retested in the kickoff meeting 21 July were conducted satisfactory. The test to determine if the flue gas recirculation fan (FGR) could hold the loss-of-combustion air-pressure switch open when the forced draft fan failed was conducted at the worst case condition — of cold flue gas at four different forced FD fan flows. The FGR fan did not hold the switch open and FGR fan operation did not prevent an emergency shutdown.
- There is no solid evidence on the cause of some of the earlier CO spikes reported by plant personnel. Since the last site visit, the control air lines have been cleaned and a major portion of the Digital Control System (DCS) has

* °F = (°C x 1.8) + 32.

been commissioned. Additionally, there may have been some misunderstanding on the correct procedure to transfer control of the boiler from manual to automatic. Dirty airlines, miscommunicating DCS components, or improper action by the boiler operator could have generated these CO spikes.

- The first safety valve is set to open before the high steam pressure burner trip. This is a very unusual configuration. Although this does not violate the boiler code, it is not a recommended practice as it communicates to the plant staff that it is acceptable to operate a boiler when a pressure vessel protective device has been activated. The safety valve relief point may be adjusted upward as long as all the valves will discharge all the steam that can be generated without allowing the pressure to rise more than 6 percent above the highest pressure at which any safety valve is set, and in no case more than 6 percent above the maximum allowable working pressure. Additionally, components such as gauge glasses and blow-off piping have their pressure and temperature limits linked to the lowest safety valve setpoint. If the lowest safety valve setpoint is raised, those components' design limits should be verified to allow the higher temperature and pressure.
- Due to the complexity of the new system, the team strongly encouraged the boiler operators to become familiar with correct operation and maintenance procedures. Active participation in plant commissioning and an aggressive training program will help the operators become skilled in running the new plant.
- An ASME Boiler and Pressure Vessel required valve is missing in the feedwater piping. Figure 10 shows ASME Code B31.1, Fig 100.1.2(B). There should be a stop valve isolation valve between the check valve downstream of the feedwater regulation station check valve and the economizer.
- At the briefing of the PHRP staff on 24 July 1997, there was discussion whether the current configuration will permit a startup during a natural gas curtailment. Although the question was outside the team's original scope of work, the team observed that the plant will either need to use an air atomization or to pay a penalty to the gas utility to build enough steam pressure to satisfy the installed burner management system. Currently two pressure switches are installed to meet the loss of atomization trip specified in NFPA 8501, Section 6-2.4.8 (a) 8. The steam atomization steam pressure switch upstream of the atomizing steam differential control valve is now set at 70 psig. This prevents operating the boiler with inadequate steam atomization. The option of proving flow by differential pressure across an orifice in the steam line as shown in NFPA 8501, Figure A-4-1.8 (Figure 11 in this report) is also acceptable as long as the burner manufacturer will certify that good steam atomization will occur with only 50 psig supply steam.



ADMINISTRATIVE JURISDICTION AND TECHNICAL RESPONSIBILITY

Boiler Proper — The ASME Boiler and Pressure Vessel Code (ASME BPVC) has total administrative jurisdiction and technical responsibility. Refer to ASME BPVC Section I Preamble.

Boiler External Piping and Joint (BEP) — The ASME BPVC has total administrative jurisdiction (mandatory certification by Code Symbol stamping, ASME Data Forms, and Authorized Inspection) of BEP. The ASME Section Committee B31.1 has been assigned technical responsibility. Refer to ASME BPVC Section I Preamble and ASME B31.1 Scope, Para. 100.1.2(A). Applicable ASME B31.1 Editions and Addenda are referenced in ASME BPVC Section I, Para. PG-58.3.

Nonboiler External Piping and Joint (NBEP) — The ASME Code Committee for Pressure Piping, B31, has total administrative and technical responsibility. See applicable ASME B31 Code.

FIG. 100.1.2(B) CODE JURISDICTIONAL LIMITS FOR PIPING — DRUM TYPE BOILERS

Figure 10. ASME Code B31.1, Fig 100.1.2(B).

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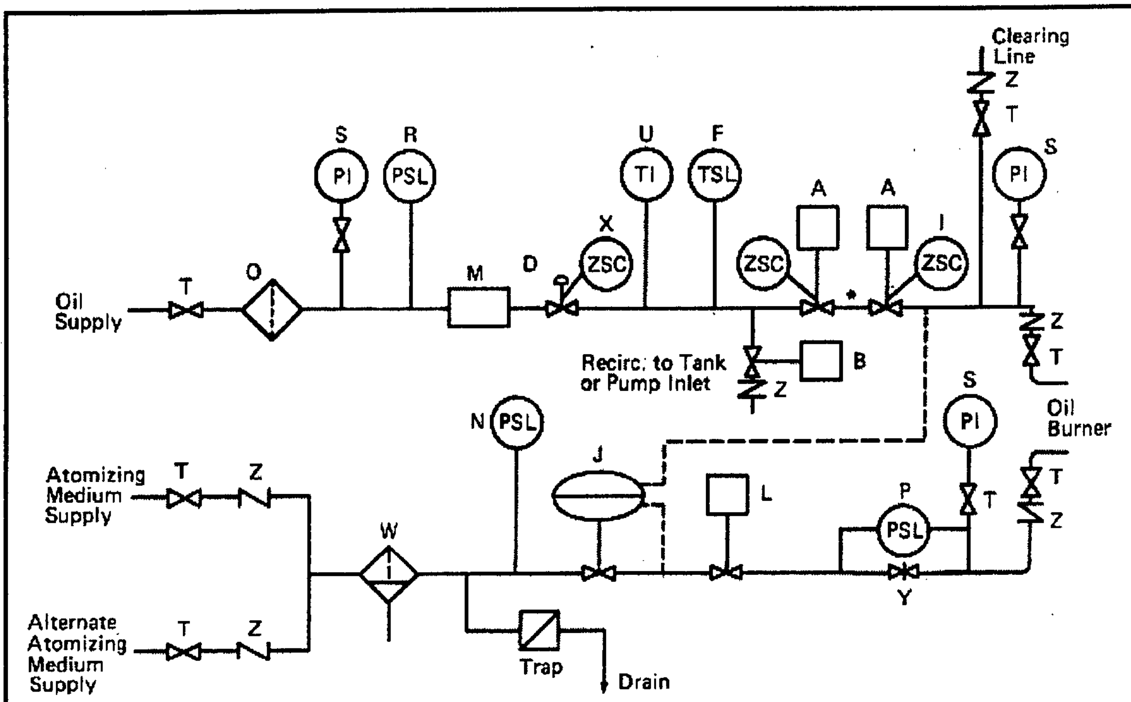


A Safety shutoff valve, spring closing (NC)
B Oil recirculation valve atomizing(NO) (optional for unheated oil)
D Oil flow control valve
F Low oil temperature switch (not applicable for unheated oil)
I Closed position interlock on safety shutoff valve
J Atomizing medium differential control valve
L Automatic atomizing medium shutoff valve
M Oil meter (optional)
N Low atomizing medium pressure switch
O Oil strainer
P Atomizing medium flow interlock differential switch, or pressure interlock switch
R Low pressure switch
S Pressure gage
T Manual shutoff valve
U Oil temperature gage (optional for unheated oil)
W Atomizing medium strainer
X Low fire start switch
Y Atomizing medium flow orifice
Z Check valve

Safety Shutdown Interlocks (not shown)

Flame detector(s)
Excessive steam pressure interlock
Auxiliary low water cut-off (one required)
Combustion air supply interlock

*Caution: Means shall be provided to prevent or relieve excess pressure between these valves

Figure 11. Typical fuel and atomization medium systems and safety controls for the burner (from NFPA 8501, Figure A-4-1.8).

Applicable sections regarding this change in steam atomization from NFPA 8501 (Single Burner Boilers) are as follows:

> 6-2.4.8 Any of the following conditions shall accomplish a safety shutdown, and the burner shall not be allowed to recycle until a qualified operator determines the cause of the shutdown and takes the necessary corrective action to assure that safe operating conditions prevail before restarting:
>
> (a) For oil:
>
> 1. Low fuel pressure.
> 2. Low temperature of heated oils.
> 3. Loss of combustion air supply.
> 4. Loss of or failure to establish flame.
> 5. Loss of control system actuating energy.
> 6. Power failure.
> 7. Low water level as determined by the auxiliary low water cutout.
> 8. Loss of atomizing medium, where used, as interlocked by flow or two pressure switches, one located at the service connection and the other at the burner, either one of which shall initiate a safety shutdown on low pressure.
> 9. Excessive steam pressure or water temperature.

5 Site Visit 3-5 November 1998

A team of engineers assembled by CERL conducted a site visit to the PHRP 3-5 November 1998. The team consisted of Charles M. Schmidt (SAI), A. Henry Studebaker, Mark Coleman, and Chip Matheson (NFESC), and Michael K. Brewer (CERL). The PHRP originally outlined four issues (No. 1-4) for the team to address, and during the site visit, added three additional questions (No. 5-7) for the team:

1. Examine and tune the boiler
2. Boiler feed pump recirculation orifice
3. Flashing makeup in blowdown, heat exchanger
4. Windbox dampers
5. Chemical feed system
6. Condensate polisher
7. Pipe hangers.

Examine and Tune Boiler.

The team was tasked to examine and tune the boiler with the O_2 sensor moved to the operating floor. The modification was made on boiler #4. Since the boilers are digitally controlled, the team needed to have a technician available who was familiar with the controllers at the PHRP to make the needed adjustments based on the team's findings. Mark Coleman (NFESC) guided the team on the boiler tune. The team concurred that the new O_2 sensor position is satisfactory. The installed O_2 sensor agreed with the portable test equipment. The team ran tests at 10 percent increments from 10 to 100 percent as indicated on the boiler master on gas and #2 oil. Appendix A contains the results. The test data suggests the boiler should be re-tuned to improve efficiency. The O_2 levels can be reduced until CO is detected. A target is to reduce O_2 levels until 100 ppm CO is observed in the flue gas. On gas, there is more room to tune. Oil is satisfactory, but it may be possible to achieve a reduction of ½ percent of O_2 before CO increases. The turndown on oil is only about 5:1. On oil, the burner produced high levels of CO concurrently with high O_2 levels at the 10 and 20 percent setpoint.

On gas, the team observed the installed boiler CO sensor was constant at 53 ppm while portable test equipment indicated zero PPM from 20 to 100 percent load when firing natural gas. (At 10 percent load, testing was suspended when CO increased to 700 ppm and continued to increase.) The team recommends recalibrating the CO monitor on the boiler.

The team observed that, unless the O_2 trim controller was set at neutral control with the process variable (PV) at zero, the O_2 trim controller remained in a state of trying to constantly cut back on the air. Typically, the PV for the O_2 trim for neutral trim should be at 50 percent. On oil at loads above 80 percent, the O_2 on PV and the manipulated variable (MV) ranged from 50 to 78 percent. This suggests that the O_2 trim is trying to increase airflow, but is still not set up correctly.

The team observed that the gas meter and the steam flow meter are not in agreement. The oil meters and steam meters were also not in agreement. Calculations indicate the metered gas flow rate is only half of the metered steam flow while the oil flow was only 86 percent below the expected fuel rate for the corresponding steam flow.

Boiler Feed Pump Recirculation Orifice

The team was tasked to provide a suggestion or opinion on options to reduce the inefficiencies on the boiler feed pump recirculation orifice line.

Mark Coleman of NFESC provided a good discussion of the options (outlined below). Three methods are used to address the need for recirculation of feedwater through constant speed feed pumps.

The team looked at the current configuration. The present system strategy is reliable and adequate. The orifice recirculation line will prevent inadvertent dead heading (and potential pump damage or casing explosion). However, it appears that the pumps are not optimized for this strategy. The pump curves show that 50 to 68 percent of the pump capacity is recirculated. Typically, 1/4 to 1/3 of the pump capacity needs to be recirculated.

Other strategies to avoid pump cavitation or damage are relatively costly and maintenance intensive. The team can look at the pump curves and estimate the saving of using VFD's (if desired). However, for pumps of this size, the payback is expected to be marginal. The pump hydraulic characteristics also need to be considered. Most single inlet pumps require some minimum flow. Most pumps

cannot be operated below one-third of their maximum capacity. The curves for the various speeds will need to be examined to ensure that, as the VFD slows down the pump, unstable flow conditions will not occur. Use of recirculation valves are possible, but are maintenance intensive. They are susceptible to failure by fouling and require annual maintenance

Recirculation Line with a Fixed Flow Orifice Plate.

The use of a recirculation line with a fixed flow orifice plate is the current method used at the PHRP. The main advantages to this method is that it requires very little maintenance. Operators never have to worry about the pumps "dead heading" (a condition similar to pump cavitation, which is very hard on the equipment) when feedwater flow rates are low. Also, this is the least expensive method (in terms of initial cost) for protecting constant speed pumps from "dead heading." A disadvantage is that this method will cost the most in lost electrical energy from the pump's constant recirculation regardless of the feedwater demand. In other words, the pumps will always recirculate a fixed amount back to the inlet side of the pump when the feedwater demand by the boilers ranges from zero to 100 percent. Therefore pumps have to be oversized for the actual boiler demand since a portion is always required for recirculation.

Flow Sensing or Pressure-Sensing Recirculation Valve.

These valves generally operate on a complicated spring and lever mechanism that senses flow or pressure on the outlet side of the pump. For example, when the flow is below a predetermined level, the recirculation valve will open to allow water to flow through the recirculation line to upstream of the pump (usually the deaerating tank). When the flow is above the present level, then the recirculation valve will prevent flow through the recirculation line and 100 percent flow will go through to the boilers. The obvious advantage of this method is that the pumps can be sized to meet boiler feedwater demand, that is to say, they need not be oversized for continuous recirculation. This saves money in the form of smaller pumps and less energy demands.

However, recirculation valves are generally expensive (e.g., the recirculating valves installed at NAVSTA Everett, WA cost just over $3,000.00 apiece — without installation costs). Also, since these valves are mechanically very complicated, they are more prone to failure and can require extensive maintenance. For example, at the Everett plant, a small amount of iron oxide from the pipes collected in the valves interfering with the seating of the valves on the recirculation side of the valve. This caused continuous recirculation until the valves were cleaned, the source of iron oxide eliminated, and the valve seals replaced. How-

ever, when working properly, these valves do a very good job of getting the most value out of constant speed feedwater pumps.

Variable Speed Drive Pumps.

Using a controller (a basic feedback loop control with gain, integral, and derivative adjustments) the rotational rate and hence flow of a pump can be regulated to maintain a constant feedwater header pressure (setpoint). This system entirely eliminates the need for any type of recirculation. Therefore, energy demands are a function of feedwater demand, saving the power required to run a constant speed pump at a set rpm 100 percent of the time. This system is very expensive to install, set up, and troubleshoot. However, if installed in a plant from the beginning, this type of feedwater pump system (and boiler FD fans as well) save significant amounts of money in the form of lower energy demands and extended equipment life (since pumps do not run at full load 100 percent of the time).

Flashing Makeup in Blowdown, Heat Exchanger.

The team was tasked to provide a suggestion or opinion on options to eliminate flashing of makeup in lowdown heat exchanger. There are times when the makeup rate is low enough so that the heat recovered from the continuous boiler blowdown causes the makeup water to flash to steam. PHRP has some initial ideas on some modifications, but would like input from the team.

Pending review of the drawings of the bottom blowdown tank, the team recommended installing a bypass at the surface blowdown heat exchanger to direct the surface blowdown to the bottom blowdown tank during periods of low flow or heat exchanger maintenance. The piping should be specified to withstand two-phase flow. The PHRP is also considering directing the surface blowdown through an immersion heater in the condensate storage tank before going to the blowdown heat exchanger.

Windbox Dampers

The team was tasked to provide a suggestion or opinion on options to eliminate or minimize the cause of the degradation of the opposed blade dampers inside the windbox controlling the recirculated flue gas flow. PHRP reported that the dampers were severely corroded. The manufacturer of the windbox has offered

to modify the dampers using a new design if PHRP will send the assembly to the manufacturer.

The team inspected the windbox and concurred with PHRP that unacceptable amounts of moisture were being deposited where the flue gas enters the windbox (Figure 12). The moisture has and will continue to cause excessive corrosion on the recirculated flue gas dampers, gas line in the windbox, and the gas ring. The corrosion will greatly shorten the life the burner. The team can investigate the life expectancy of the burner ring. Vincent Hock at CERL can provide corrosion expertise support. The team can also provide a list of burner manufacturers who have successfully installed low NOx burners at DOD sites if desired.

Chemical Feed System

The team was tasked to provide an opinion on adding chemical feed pots for each boiler as part of the proposed chemical feed system changes. Adding the capability to maintain oxygen scavenging chemical treatment in shutdown boilers will help increase the life of the pressure vessel. SAI recommended that piping and a pump also be installed to continuously recirculate the treated water to protect all the internal boiler and economizer surfaces during wet layup.

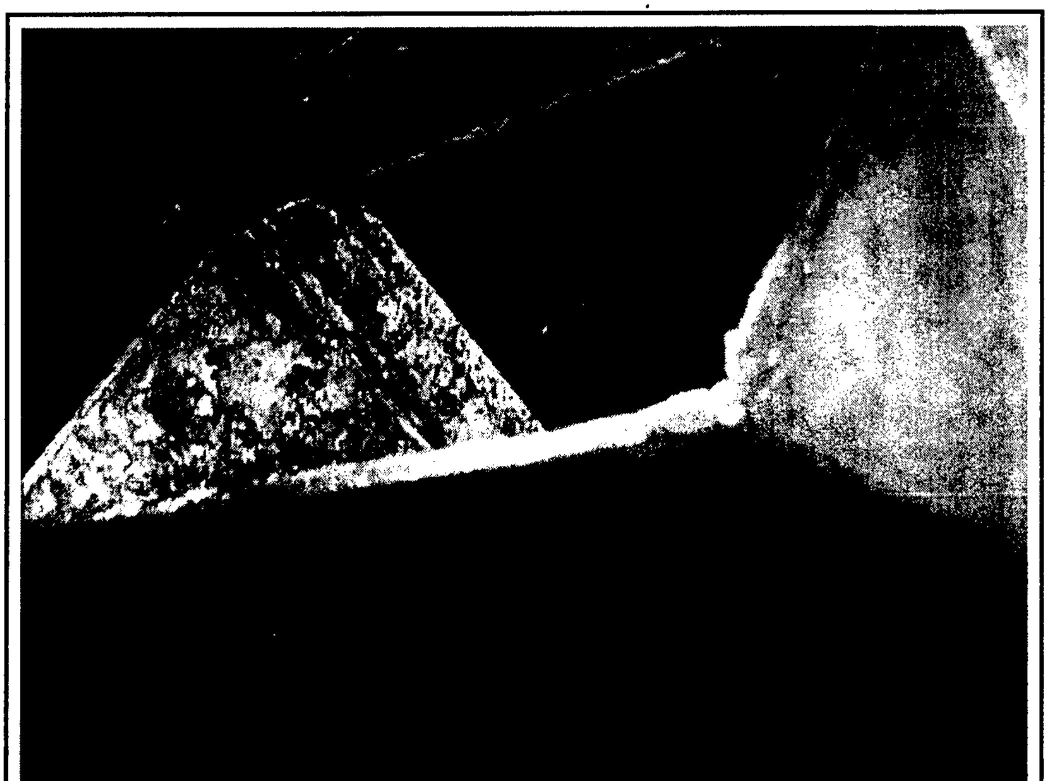


Figure 12. Windbox corrosion November 1998.

Condensate Polisher

The team was tasked to provide an opinion of the modifications made to the polisher controls. The polishers have been modified. The softeners have not yet been modified.

All the valves should be replaced in a similar fashion as has occurred on the polisher. It appears that the current softener uses untreated water for the fast rinse to waste (last rinse before going on line). It is preferable to use treated water for the last rinse to waste before coming on line, to avoid introducing raw water to the makeup water system routinely. The polishers appear to be backwashed with cold raw water. In addition to adding raw water to the condensate, the cold water will thermally shock the resin and shorten its life span. The team recommends adding a treated makeup water tank to provide a source for the fast rinses. A heat exchanger should also be considered to preheat the polisher rinses and washes to minimize thermal shock to the resin.

Pipe Hangers

The team was tasked to provide an opinion on the use of threaded pipe hangers on large steam pipe. The team cannot assess the structural design with the available funding. However, there are pipe stress analysis tools available. If there is a doubt, the program should be run. SAI can provide more information on the software.

6 Other Low NOx Burner Experience

The team of engineers assembled by CERL collected the following information regarding other burners.

Burner Manufacturer A

For burners of the size in question burning gas and #2 oil, this manufacturer usually provides induced draft flue gas recirculation. If using forced flue gas recirculation, the flue gas is brought in a separate chamber and then diffused around the burner evenly. This is usually for larger burners. If only one type of fuel is used, the induced flue gas is induced across an orifice. If the burner is dual fueled, a 2-position valve is used so that the appropriate amount of flue gas is used for each fuel. Manufacturer A desires to sell a complete burner package.

Burner Manufacturer B

This manufacturer makes both forced and induced flue gas recirculation. If using forced draft recirculation, a static mixer upstream of the windbox is used for gas and #2 oil. If burning #6 oil, the flue gas is brought into the burner via a stainless steel bussel so that flue gas never contacts the FD fan, windbox, burner, or register. Stainless steel must be used due to acid from the sulfur in #6 oil. For most boilers in the 50,000 pph range, induced flue gas recirculation is used. In general for these low NOx burners, the key performance criteria are: no flame impingement, low CO with in specification NOx, reasonable O_2 (2 to 3 percent consistently), and no particulate. Manufacturer B mostly sells complete burner packages so that the system will operate as designed.

Burner Installation C

A number #5 fuel oil low NOx burner was specified for a DOD site. For a prescribed #5 oil, the burner performance was required to be:

- O_2: 3 % Max (40-100% load), 4% max (25-40%), 6% max (17-25%)
- CO: 100 ppm Max (17-100% load)

- NOx: 35 lb NO_2/MBTU input (17-100% load)
- Opacity: 10 max (17-100%)
- Flame Impingement (5 minute test): less than 2 percent of time below 80 percent load, less than 10 percent of the time 80 percent load and above.

Although not specified, the installed system was a staged combustion burner.

Burner Installation D

A forced draft flue gas burner was installed with flue gas to the windbox at a Navy site. The flame was unstable and poor combustion was observed. The installer had to model the windbox and install perforated plates to get the flue gas and combustion air thoroughly mixed and to achieve stable combustion.

Burner Installation E

An induced draft and stage combustion burner was installed at a Navy site. The furnace experienced violent pulsations at certain loads. The FD fan had inlet and outlet dampers. The fan outlet dampers were removed. The site is still working to get good combustion at all loads.

Burner Installation F

A forced recirculated flue gas to the windbox burner was installed at an AF site. The site does not use the recirculated flue gas as the burner works fine without the flue gas. The site burns gas, and #1 and #2 oil.

Burner Installation G

A forced recirculated flue gas to the windbox burner was installed at a NASA site. The site burns natural gas only. The site does not use the boiler much because it is a backup boiler. Even though it is infrequently used, the site reports that the bearings on the recirculating fan has been replaced much more often than expected. The team will continue to research low NOx burner performance and construction history. Recent CERL research indicates the technology has operational problems (CERL Technical Report [TR] 99/81, *Survey of Department of Defense Facilities with Low NOx Burners* [September 1999]). Appendix A to this report includes sections of the data sheets that form the basis for these opinions on the safety of the burner.

7 Lessons Learned

The team was grateful for the cooperation of the PHRP, Baltimore District, the design engineering staff, and the contractors. In summary, several lessons can be extracted from the plant commissioning:

1. Apply digital controls with caution. Many times a less sophisticated system, though not as efficient, is more reliable and easier to maintain. Additionally, if the more complex system is not properly tested and aligned, it may be less efficient than an analog system.
2. Do not try to use electronics to remedy lack of quality in mechanical systems. If sophisticated control systems are used, the mechanical components they control must be precise, reliable, and repeatable.
3. Government engineers and plant operators need to understand and apply codes and standards (NFPA, ASHRAE). It is in the best interest of the government to be as knowledgeable of the engineering standards as the private sector design agent. Although the design and construction is contracted out, the system owners (the government) need to have the time and skill to review plans and identify code and standard violations.
4. In construction or repair, the resident engineer can become overloaded. If there is not an engineer familiar with the particular system requirements, it is difficult to quickly resolve design problems.
5. System operators (the users) need to aggressively participate in testing and commissioning. It is in the best interest of the end user (operator) to actively participate in the plant testing and commissioning. This has a double benefit of helping the operators become familiar with the dynamics of the new plant and as well as providing another layer of quality control.
6. Few shortcuts are possible in commissioning. The problems and flaws not discovered in an abbreviated commissioning will result in extra costs later due to rework or poor system performance. There is always pressure to abbreviate plant commissioning procedures as a way to get a project back on schedule. However, if a system problem is not identified in commissioning, it is frequently more expensive in both time and money to remediate the problem later on.

8 Summary and Recommendations

Summary

This study has researched several issues related to the installation and performance of new low NOx boilers at PHRP. A team of engineers conducted on-site testing and inspection to assess whether the installed system met the intent of "parallel metered combustion controls" to produce safe and stable low NOx combustion. The team made four site visits to investigate the adequacy and safety of the primary air and flue gas recirculation configuration with regard to combustion control, to address items of special interest to the PHRP, and to make recommendations to improve system performance. The team received exemplary support from the installer, PHRP, and PRO. All required testing, and additional requested support was accomplished in a short time.

Recommendations

The following recommendations should to help resolve the problems observed and identified during the site visits.

Windbox Stratification

The windbox stratification will reduce the design margin for the burner to operate in. However, with a clean oil gun, calibrated sensors, and communicating controls, the boiler ran well at 50 percent and higher load. The boiler also runs satisfactorily at lower loads on oil. However, if the oil guns are not clean or the sensors and controls are not aligned, the boiler runs unsatisfactorily.

The gas flame is adequate at low and high fire. The stratification makes it difficult to get a well-formed flame.

The windbox is of a simple design. Since the flue gas is stratified from the combustion air, condensation is occurring. The condensation is probably more severe when operating on gas. Corrosion is already occurring and will shorten the life of the windbox. The windbox will probably need to be reworked much earlier than normal.

If clean oil guns, clean steam, calibrated sensors, continuous communications and stable gas pressures are available, the burner is adequate. Most vendors use double registers and/or baffles to thoroughly mix the flue gas. Additionally, the NFPA recommends an O_2 sensor to monitor the mixture.

Boiler Controls

Instrument alignment is very important and a calibration program should be in effect or started soon by the plant. The primary sensors for any control system are also very important. Using FD fan to windbox DP is very economical, and probably adequate as long as furnace pressure oscillations are not sensed in the windbox. If a dirty oil gun is used, the flame pulsations may introduce an unsatisfactory amount of noise into the control system.

Control communications are critical. The large CO excursion observed was due to the loss of the airflow signal. As a start, wiring harnesses should be checked throughout the plant to ensure good data bus connections.

Some level of commissioning testing should continue to resolve operational problems. Test equipment should be used to verify that the primary sensing element and associated controls respond as designed.

Operation and Maintenance

Training is critical. This plant is very different from the old plant; plant operators need training. Although a state-of-the-art simulator is installed, plant floor personnel need training in operating procedures and maintenance practices. Several of the more difficult problems seen during the testing were related to the digital controls. DCS maintenance training will be needed if the plant is to troubleshoot future problems. Some of the problems were attributed to insertion of “step functions” when transitioning from manual to auto during loss of communications. Some of the “step function” events might be solvable with training.

Appendix A: Boiler Test Results, 3-5 November 1998

Utility Modernization Analysis — Heat Plant Data

Existing Equipment

Plant Data

Plant Peak Load		**lbs/hr** or MBbu/hr (circle one)				
Plant No-Load Load		**lbs/hr** or MBbu/hr (circle one)				
Reported M/U Rate (Daily Ave)		gallons				
Plant Annual Fuel Use				Btu/lbs	0	MBTU/yr
Plant Annual Steam Prod.		KLbs stm	180	Days Oper.	#DIV/0!	Ave Eff
Peak Plant Capacity	160	lbs/hr or **MBTU/hr** (circle one)				
Plant Annual Oil Use		Gallons	138,150	Btu/gal	0	MBTU/yr
Plant Annual Gas Use		ccf	0.1	MBTU/ccf	0	MBTU/yr

Serial #	93-110-4	93-110-2	93-110-1	93-110-5	93-110-6	93-110-3
Boilers	Unit #1	Unit #2	Unit #3	Unit #4	Unit #5	Unit #6
Capacity	40	40	40	40	40	40
Type	WT	WT	WT	WT	WT	WT
Convection Heating Surface (ft2)	2993	2993	2993	2993	2993	2993
Radiant Surface (ft2)	87.4	87.4	87.4	87.4	87.4	87.4
Total HS	3863.4	3863.4	3863.4	3863.4	3863.4	3863.4
MAWP Pressure	175	175	175	175	175	175
Oper Pressure						
Safety Set Press						
Manufacturer	English	English	English	English	English	English
Built	1994	1994	1994	1994	1994	1994
NBPVII No.	37	34	33	38	49	36
Last Inspection Date						
Condition						
Furn Vol (ft3)	822	823	824	825	826	827
Burner Data	STI 50K	STI 50K	STI 50K	STI 50K	STI 50K	STI 50K
Primary Fuel	N.Gas	N.Gas	N.Gas	N.Gas	N.Gas	N.Gas
Alternate Fuel	#2 Oil	#2 Oil	#2 Oil	#2 Oil	#2 Oil	#2 Oil
Controls	B-Babcok	B-Babcok	B-Babcok	B-Babcok	B-Babcok	B-Babcok
Safety Vlv						
WS Internal						
FS Intermal						

ABMA Corr	Rad Loss K	35.42700
	Rad Loss b	-1.02120

Utility Modernization Analysis — Heat Plant Data

Fuel Data

Gas

	1,000	Btu/scf
HHV	21,800	Btu/lb
Combustion Eff		
Fuel	% Wt (lbs/lb AF)	
C	69.26%	
H2	22.68%	
O2	0.00%	
N2	8.06%	
S	0.00%	
H2O (liq)	0.00%	
Ash	0.00%	
	100.00%	

Oil

S.G.	0.852885	
HHV	19450	Btu/lb
Combustion Eff		
Fuel	% Wt (lbs/lb AF)	
C	80.65%	
H2	13.94%	
O2	4.70%	
N2	0.34%	
S	0.36%	
H2O (liq)	0.00%	
Ash	0.01%	

Coal

	Btu/lb	
HHV		
Combustion Eff		
Fuel	% Wt (lbs/lb AF)	
C	80.65%	
H2	13.94%	
O2	4.70%	
N2	0.34%	
S	0.36%	
H2O (liq)	0.00%	
Ash	0.01%	

Utility Modernization Analysis — Boiler Data Sheet

Gas (MBTU/ccf) 0.1

Boiler Outlet						
Start Time	11:30	12:10	13:33	14:10	15:10	15:40
Stop Time	12:10	13:33	14:10	15:10	15:40	16:40
Boiler Master (%)	50.0%	60.0%	70.0%	80.0%	90.0%	100.0%
Amb Temp (F)	75	73	75	74	73	75
O2 (wet)	3.0%	3.5%	3.7%	3.9%	4.3%	5.0%
CO(ppm-wet)	53	53	53	55	55	55
Elapse Time (hr)						
Fuel Oil (gals)						
Fuel Oil Rate (gph)						
Efficiency (%)	81.9%	81.9%	82.1%	81.7%	81.4%	80.8%
Gas (ft3/min)	230	272	314	362	408	425
Gas (MBTU/hr)	13.8	16.32	18.84	21.72	24.48	25.5
Steam Flow (calc eff Kpph) 3	11.2989803	13.3730635	15.4621147	17.7384643	19.9180965	20.6112963
Plant/Gage Readings						
Steam Flow (Kpph) 3	18.8	23	25.88	30.62	33.94	35.07
Feedwater Flow (Kpph)	15.49	19.34	20.97	24.26	20.05	27.42
Feedwater Level (in)	0.3	0.07	0.22	0.23	0.36	0.23
Boiler Press (psig)	121.5	123	122.7	126.2	128.6	130.08
Comb Air Flow (%)	45	57.1	68.1	80.2	90	93.5
FD Fan Press (in WC)	2.18	3.14	3.93	4.9	6.2	7.17
Furn Press (in WC)	1.03	1.3	1.92	2.47	3.42	3.9
Econ OutletPress (in WC)	0.77	0.78	0.811	0.771	0.776	0.817
Econ Inlet Temp (F)	399.4	420.6	435.6	454.6	471.3	486.7
Econ Outlet Temp (F)	301.4	308.7	314.2	330.9	339.2	349.5
Feedwater Inlet Temp (F)	254.1	261.2	256.7	259.2	265.9	264.6
Fuel Gas Press (psig)	8.93	8.7	8.35	8.86	8.68	8.72
Blr Outlet						
Oxygen %	4.2%	4.3%	4.1%	4.6%	5.1%	6.0%
CO(ppm)						
Combustibles %						
NOX (ppm)	6	20	35	37	45	35
SOX (ppm)						
Econ Outlet						
Oxygen %	4.8%	5.3%	4.6%	4.8%	5.1%	6.2%
CO(ppm)						
Combustibles %						
NOX (ppm)	4	15	4		52	34
SOX (ppm)						
Roof						
Oxygen %	4.3%	5.0%	5.3%	4.6%	4.9%	5.5%
CO(ppm)						
Combustibles %						
NOX (ppm)	4	20	7	37	43	32
SOX (ppm)						

Utility Modernization Analysis — Boiler Data Sheet

Boiler Outlet						
Start Time	16:40	17:20	17:45	18:10		11:10
Stop Time	17:20	17:45	18:10	18:30	11:10	11:30
Boiler Master (%)	40.0%	30.0%	20.0%	10.0%		
Amb Temp (F)	77	74	76	77	76	71.9
O2 (wet)	2.9%	3.9%	8.0%	11.0%		3.2%
CO(ppm-wet)	54	53	56			53
Elapse Time (hr)						
Fuel Oil (gals)						
Fuel Oil Rate (gph)						
Efficiency (%)	80.8%	80.5%	78.0%	73.9%		
Gas (ft3/min)	183	137	88.8	67.4		
Gas (MBTU/hr)	10.98	8.22	5.328	4.044		
eam Flow (calc eff Kpph) 3	8.8750473	6.6176656	4.1576126	2.9883789		
Plant/Gage Readings						
Steam Flow (Kpph) 3	12.92	10.8	7.98	5.46	21.68	20.79
Feedwater Flow (Kpph)	19.96	16.97	13.97	13.37	15.52	18.44
Feedwater Level (in)	0.07	0.32	0.65	0.62	0.48	0.18
Boiler Press (psig)	121.6	119.5	121.2	119.4	121.9	122
Comb Air Flow (%)	33	21.6	20.6	20.2	55.6	50.4
FD Fan Press (in WC)	1.73	1.45	1.43	1.35	2.91	2.62
Furn Press (in WC)	0.66	0.49	0.54	0.47	1.33	1.12
Econ OutletPress (in WC)	0.74	0.78	0.768	0.785	0.8	0.77
Econ Inlet Temp (F)	404.1	376.3	366.3	366.2	413	409
Econ Outlet Temp (F)	315.2	299.2	287.4	285	305	302.8
Feedwater Inlet Temp (F)	245.6	243.2	253.9	251.5	262.3	258.6
Fuel Gas Press (psig)	8.88	8.92	8.91	9.09	8.5	8.63
Blr Outlet						
Oxygen %	3.9%	4.4%	9.2%	12.5%		4.4%
CO(ppm)			3			
Combustibles %						
NOX (ppm)	40	42	42			18
SOX (ppm)						
Econ Outlet						
Oxygen %	4.0%	4.6%	9.2%	12.5%		4.7%
CO(ppm)			3	723		
Combustibles %						
NOX (ppm)	38	44	42	25		14
SOX (ppm)						
Roof						
Oxygen %	4.1%	4.9%	9.3%			4.5%
CO(ppm)			6			
Combustibles %						
NOX (ppm)	39	42	42			10
SOX (ppm)						

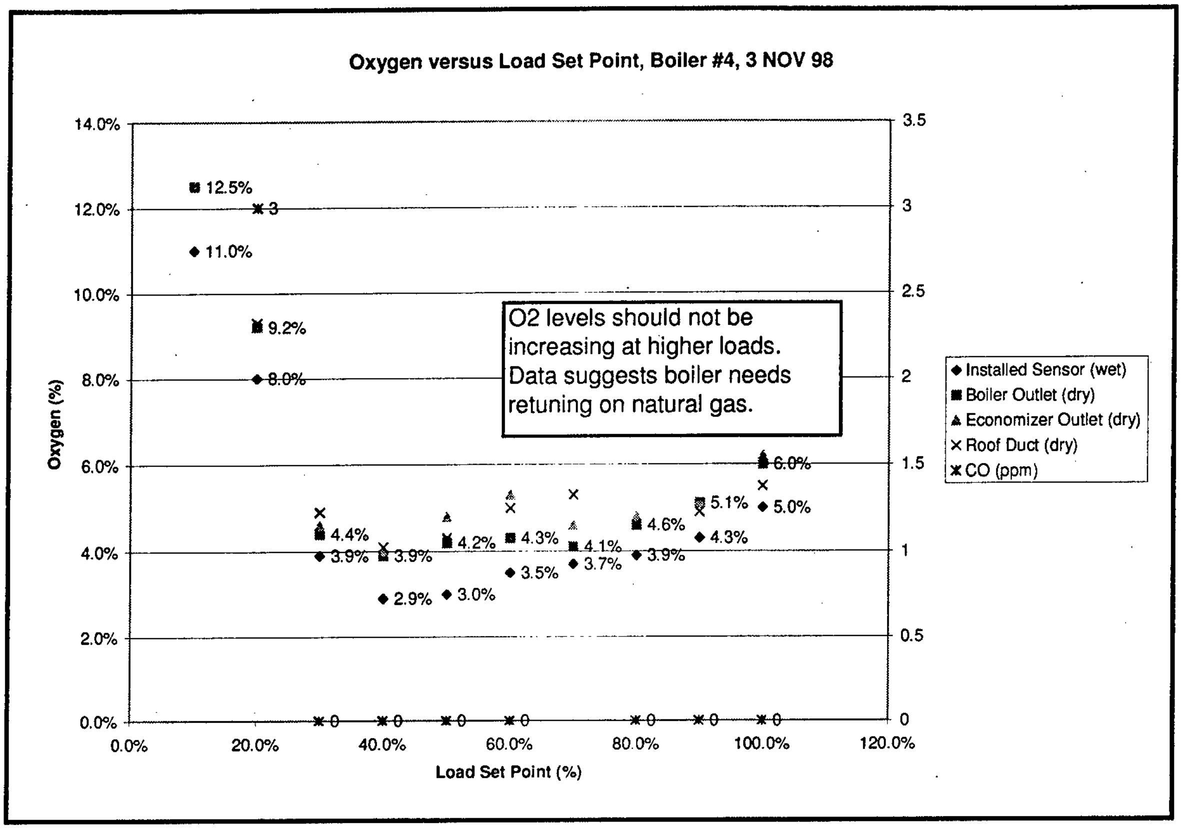
Utility Modernization Analysis — Boiler Data Sheet

Oil Btu/gal	Oil S.G.	Oil Btu/lb
138,150	0.852885	19,450

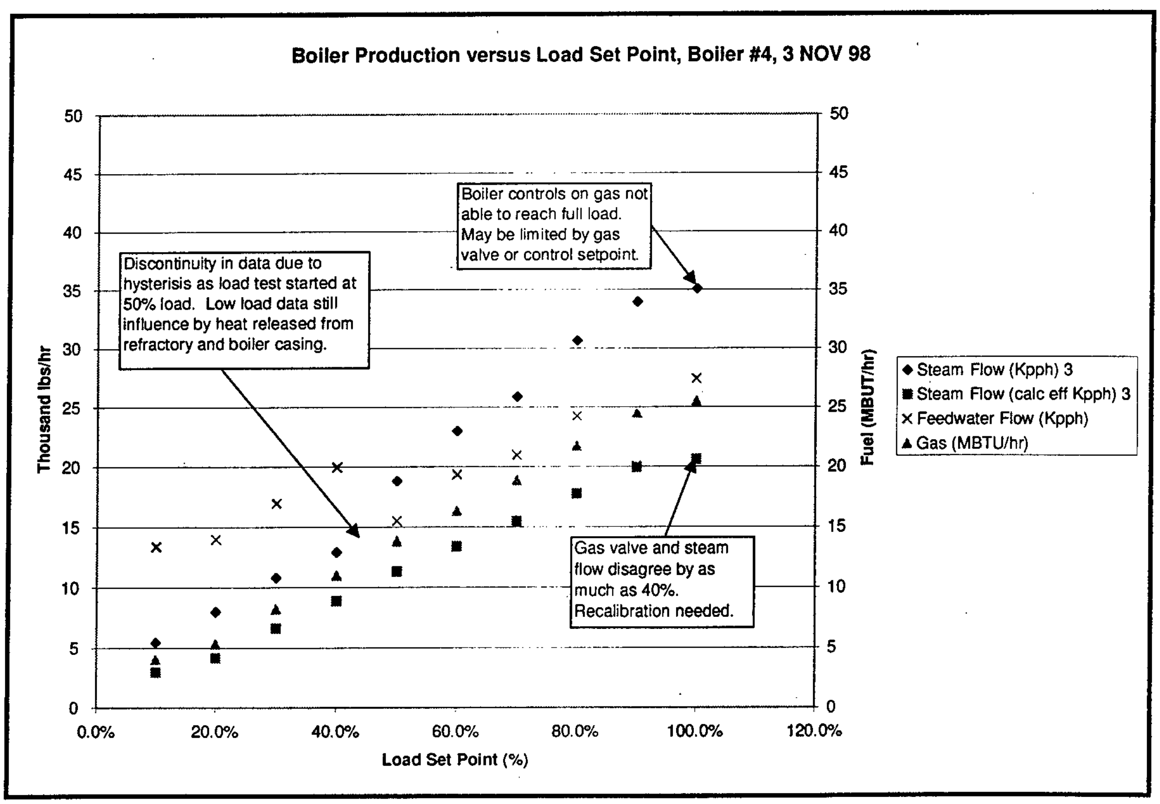
Boiler Outlet						
Start Time	14:31	14:42	14:58	15:23	15:51	16:19
Stop Time	14:42	14:55	15:20	15:46	16:16	16:42
Boiler Master (%)	10.0%	20.0%	30.0%	40.0%	50.0%	60.0%
Amb Temp (F)	69	77	78.4	76.9	78.7	77.9
O2 (wet)	9.3%	9.3%	3.2%	3.2%	2.9%	3.0%
CO(ppm-wet)	166	159	63	62	64	64
Elapse Time (hr)	0.2	0.2	0.4	0.4	0.4	0.4
Fuel Oil (gals)	12	14	30	50	62	67
Fuel Oil Rate (gph)	65.45	64.62	81.82	130.43	148.80	174.78
Efficiency (%)	80.1%	80.7%	84.5%	85.3%	85.5%	85.6%
Gas (ft3/min)						
Oil (MBTU/hr)	9.04	8.93	11.30	18.02	20.56	24.15
Steam Flow (calc eff, Kpph) 4	7.24	7.20	9.55	15.37	17.58	20.67
Plant/Gage Readings						
Steam Flow (Kpph) 4	7.68	7.98	12.27	15.69	22.46	27.04
Feedwater Flow (Kpph)	13.68	18.21	18.11	15.85	17.26	18.05
Feedwater Level (in)	0.06	-0.03	-0.51	-0.48	-0.78	-0.14
Boiler Press (psig)	122.4	120.8	121.2	122.3	122.6	125.8
Comb Air Flow (%)	18.2	19.4	18.1	30.6	49.6	63.1
FD Fan Press (in WC)	1.53	1.34	1.32	1.69	2.52	3.39
Furn Press (in WC)	0.46	0.51	0.59	0.77	1.2	1.74
Econ OutletPress (in WC)	0.727	0.8	0.783	0.733	0.767	0.823
Econ Inlet Temp (F)	367.4	0.368	370.2	376.5	410.3	431.1
Econ Outlet Temp (F)	281.8	281	283.3	282.3	303.6	310.7
Feedwater Inlet Temp (F)	262.9	262.5	253.3	257.1	257.5	263.9
Fuel Oil Press (psig)	150	150	149.6	149.9	150	150.4
Fuel Oil Temp (F)	66.3	71.4	69.7	69.2	70.6	70.2
Blr Outlet						
Oxygen %	10.7%	10.6%	4.8%	3.9%	3.7%	3.7%
CO(ppm)	183	173		3	3	3
Combustibles %						
NOX (ppm)	87	90	112	111	110	110
SOX (ppm)						
Econ Outlet						
Oxygen %	10.6%	10.6%	5.0%	3.9%	4.1%	4.0%
CO(ppm)	132	137		3	3	3
Combustibles %						
NOX (ppm)	83	84	112	111	107	108
SOX (ppm)						
Roof						
Oxygen %	10.8%	10.7%	5.1%	4.3%	4.2%	4.1%
CO(ppm)	144	88		3	3	3
Combustibles %						
NOX (ppm)	82	146	111	111	110	110
SOX (ppm)						

Utility Modernization Analysis — Boiler Data Sheet

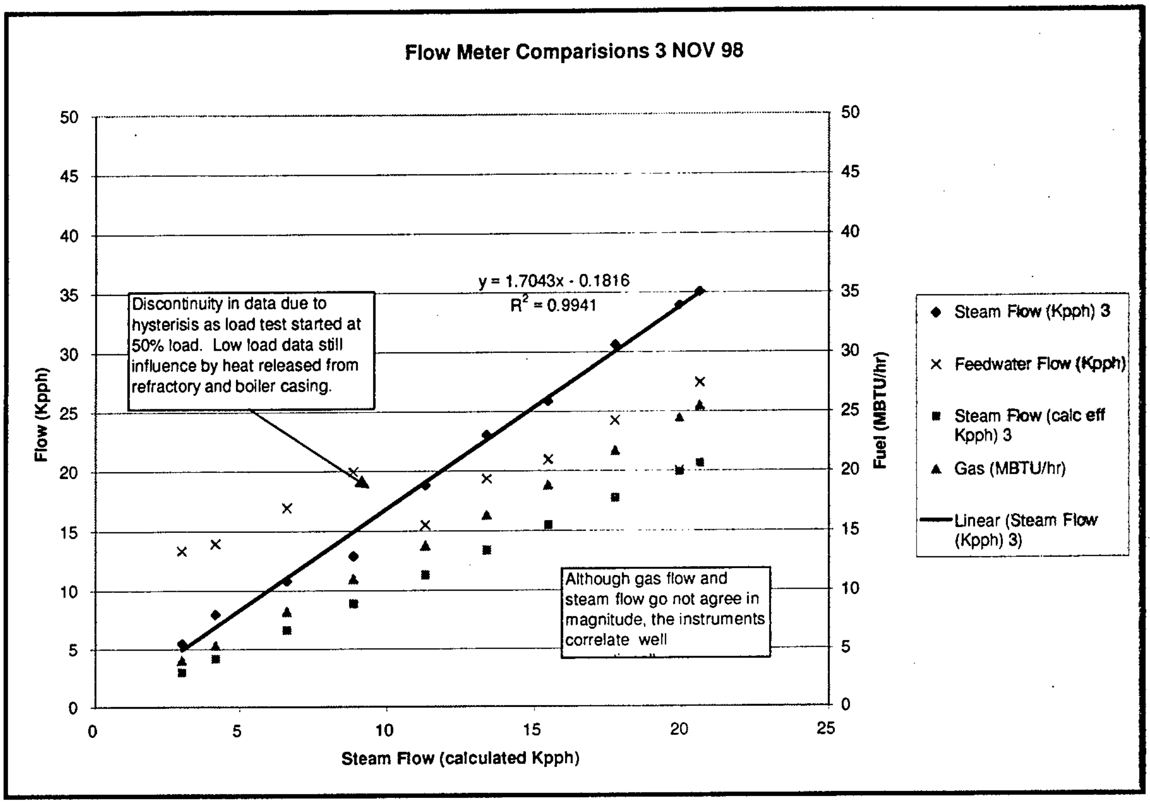
Boiler Outlet						
Start Time	16:45	17:45	18:12	18:45		
Stop Time	17:32	18:10	18:40	19:10		
Boiler Master (%)	70.0%	80.0%	90.0%	100.0%		
Amb Temp (F)	76	77.8	78.5	78.3		
O2 (wet)	3.1%	3.0%	3.0%	3.0%		
CO(ppm-wet)	65	66	68	68		
Elapse Time (hr)	0.8	0.4	0.5	0.4		
Fuel Oil (gals)	179	149	142	125		
Fuel Oil Rate (gph)	228.51	357.60	304.29	300.00		
Efficiency (%)	85.5%	85.4%	85.1%	85.0%		
Gas (ft3/min)						
Oil (MBTU/hr)	31.57	49.40	42.04	41.44		
am Flow (calc eff, Kpph) 4	27.00	42.20	35.79	35.22		
Plant/Gage Readings						
Steam Flow (Kpph) 4	31.38	37.29	40.46	40.47		
Feedwater Flow (Kpph)	24.7	25.81	26.67	30.87		
Feedwater Level (in)	-0.34	-0.89	-0.05	-0.09		
Boiler Press (psig)	125.6	127.4	133.9	135.7		
Comb Air Flow (%)	74.5	85.5	96.7	93.9		
FD Fan Press (in WC)	4.33	5.56	6.89	7.12		
Furn Press (in WC)	2.36	3.14	3.95	4.21		
Econ OutletPress (in WC)	0.724	0.815	0.799	0.811		
Econ Inlet Temp (F)	454	475.4	499	504.1		
Econ Outlet Temp (F)	325	337.9	354.4	359.8		
Feedwater Inlet Temp (F)	258.6	257.6	262.4	259.4		
Fuel Oil Press (psig)	1.56	149.6	147.8	145.8		
Fuel Oil Temp (F)	67.7	64.4	67.2	68.9		
Blr Outlet						
Oxygen %	3.2%	3.2%	3.1%	3.2%		
CO(ppm)	3	3	3	6		
Combustibles %						
NOX (ppm)	116	122	126	131		
SOX (ppm)						
Econ Outlet						
Oxygen %	3.8%	3.7%	3.1%	2.9%		
CO(ppm)	3	3	6	6		
Combustibles %						
NOX (ppm)	107	112	125	131		
SOX (ppm)						
Roof						
Oxygen %	3.7%	3.2%	3.3%	3.1%		
CO(ppm)	3	3	3	3		
Combustibles %						
NOX (ppm)	113	119	109	124		
SOX (ppm)						

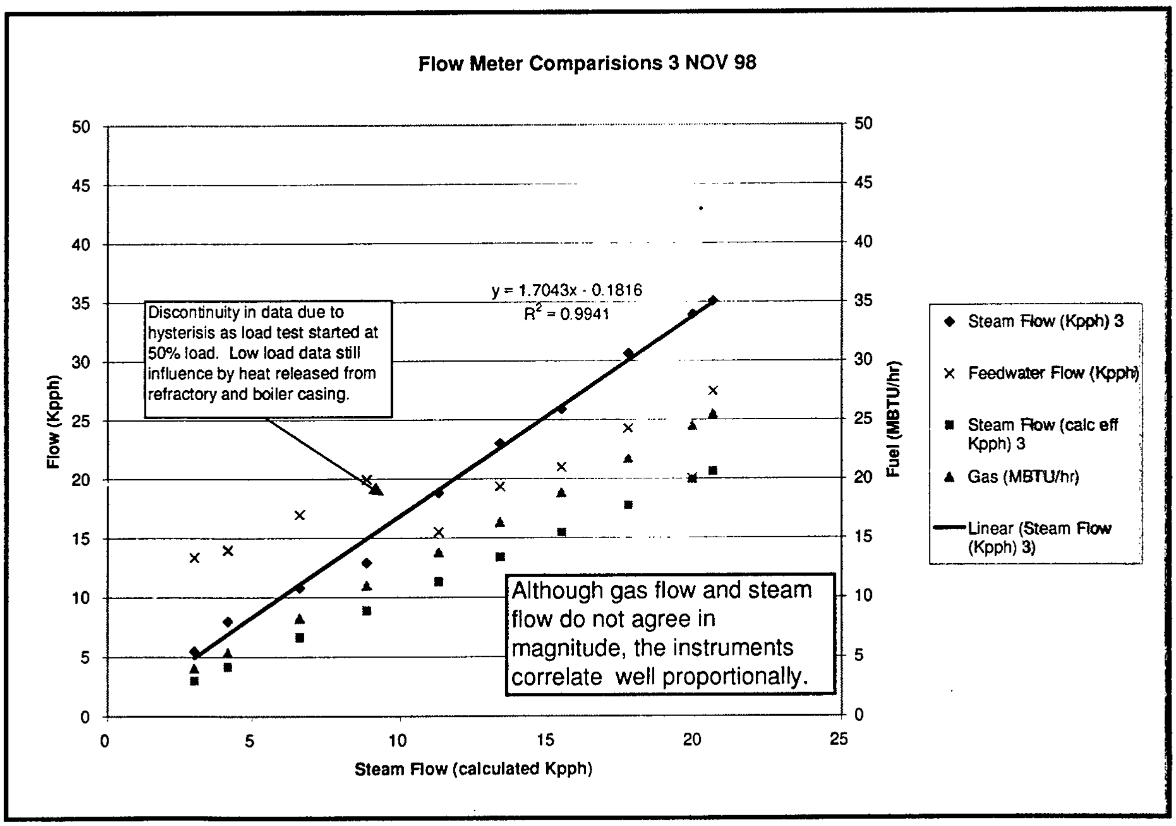


Oxygen versus Load Set Point, Boiler #4, 3 NOV 98
O2 levels should not be increasing at higher loads. Data suggests boiler needs retuning on natural gas.
Oxygen (%)
Load Set Point (%)
Installed Sensor (wet)
Boiler Outlet (dry)
Economizer Outlet (dry)
Roof Duct (dry)
CO (ppm)



Boiler Production versus Load Set Point, Boiler #4, 3 NOV 98
Boiler controls on gas not able to reach full load. May be limited by gas valve or control setpoint.
Discontinuity in data due to hysterisis as load test started at 50% load. Low load data still influence by heat released from refractory and boiler casing.
Gas valve and steam flow disagree by as much as 40%. Recalibration needed.
Thousand lbs/hr
Fuel (MBUT/hr)
Load Set Point (%)
Steam Flow (Kpph) 3
Steam Flow (calc eff Kpph) 3
Feedwater Flow (Kpph)
Gas (MBTU/hr)


Flow Meter Comparisions 3 NOV 98
y = 1.7043x - 0.1816
R^2 = 0.9941
Discontinuity in data due to hysterisis as load test started at 50% load. Low load data still influence by heat released from refractory and boiler casing.
Although gas flow and steam flow go not agree in magnitude, the instruments correlate well
Flow (Kpph)
Fuel (MBTU/hr)
Steam Flow (calculated Kpph)
Steam Flow (Kpph) 3
Feedwater Flow (Kpph)
Steam Flow (calc eff Kpph) 3
Gas (MBTU/hr)
Linear (Steam Flow (Kpph) 3)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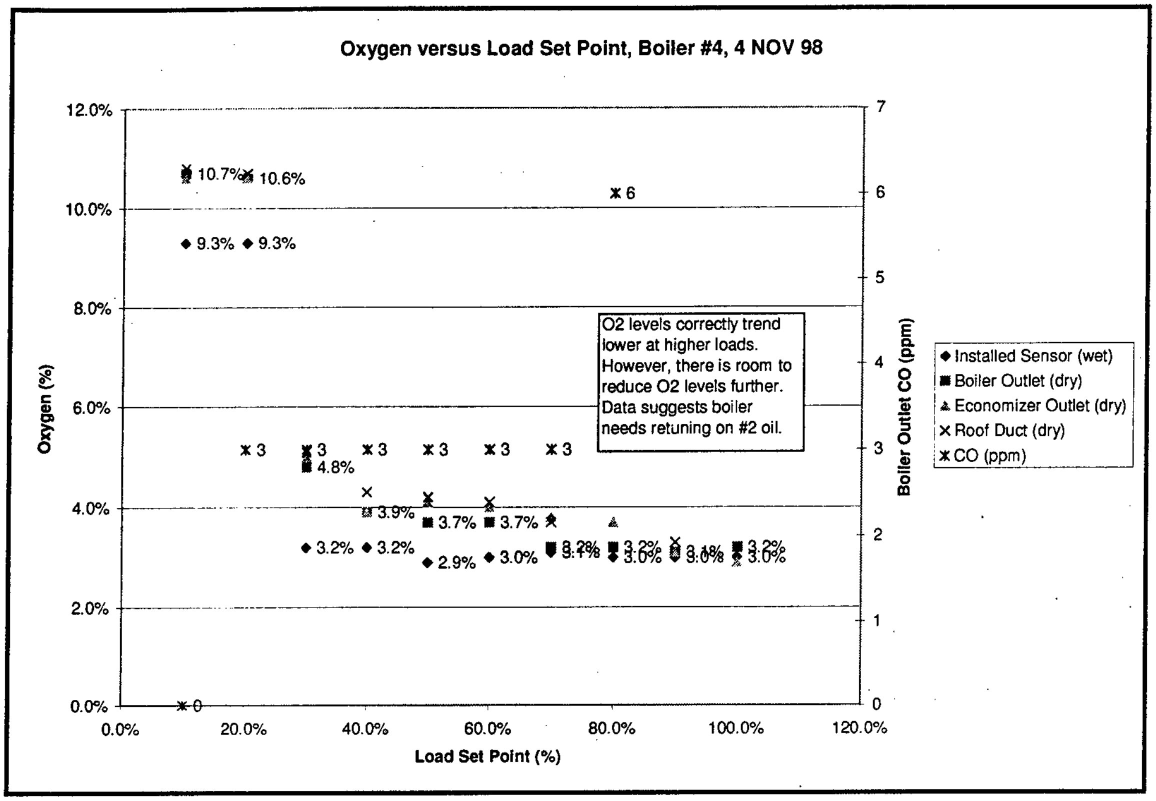
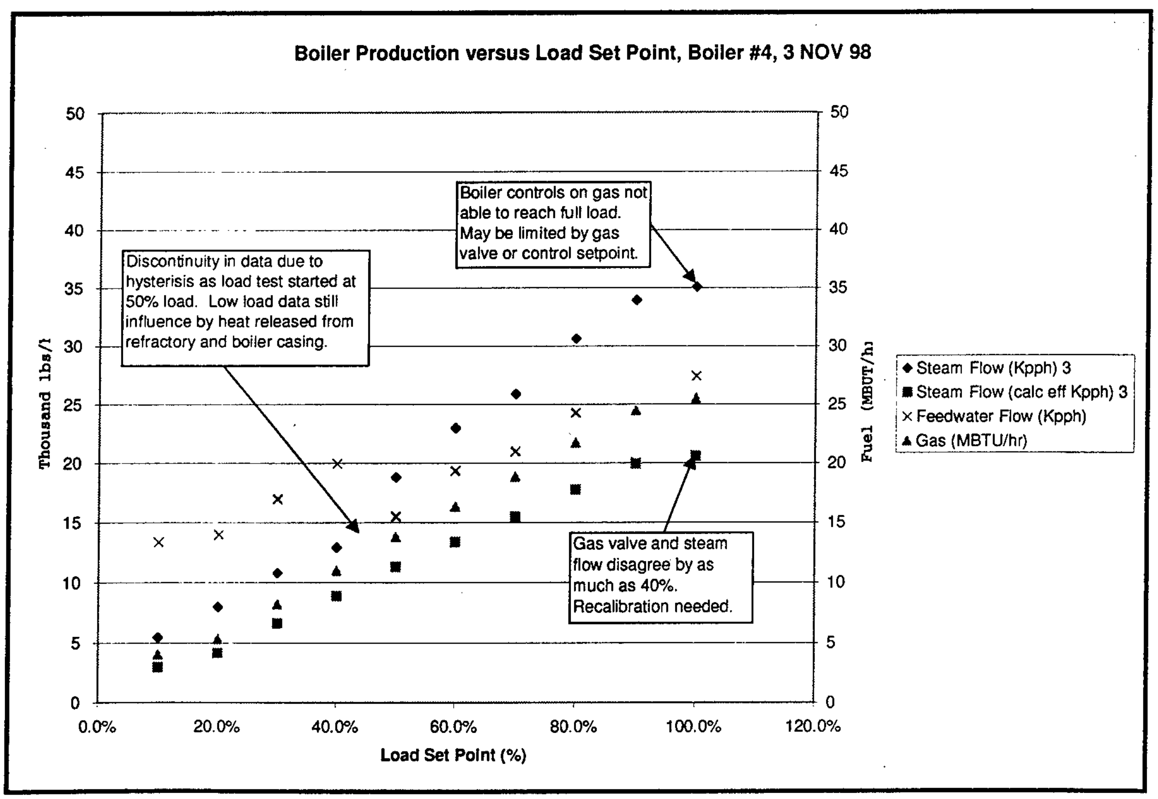
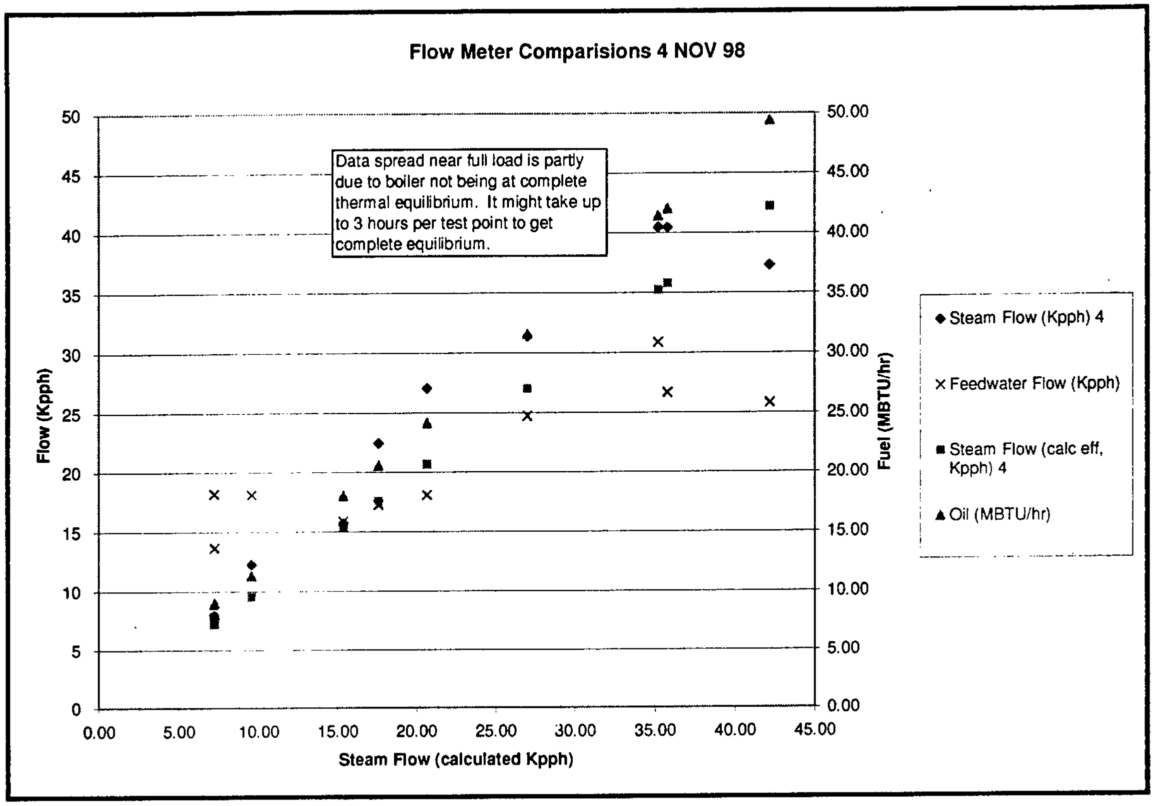
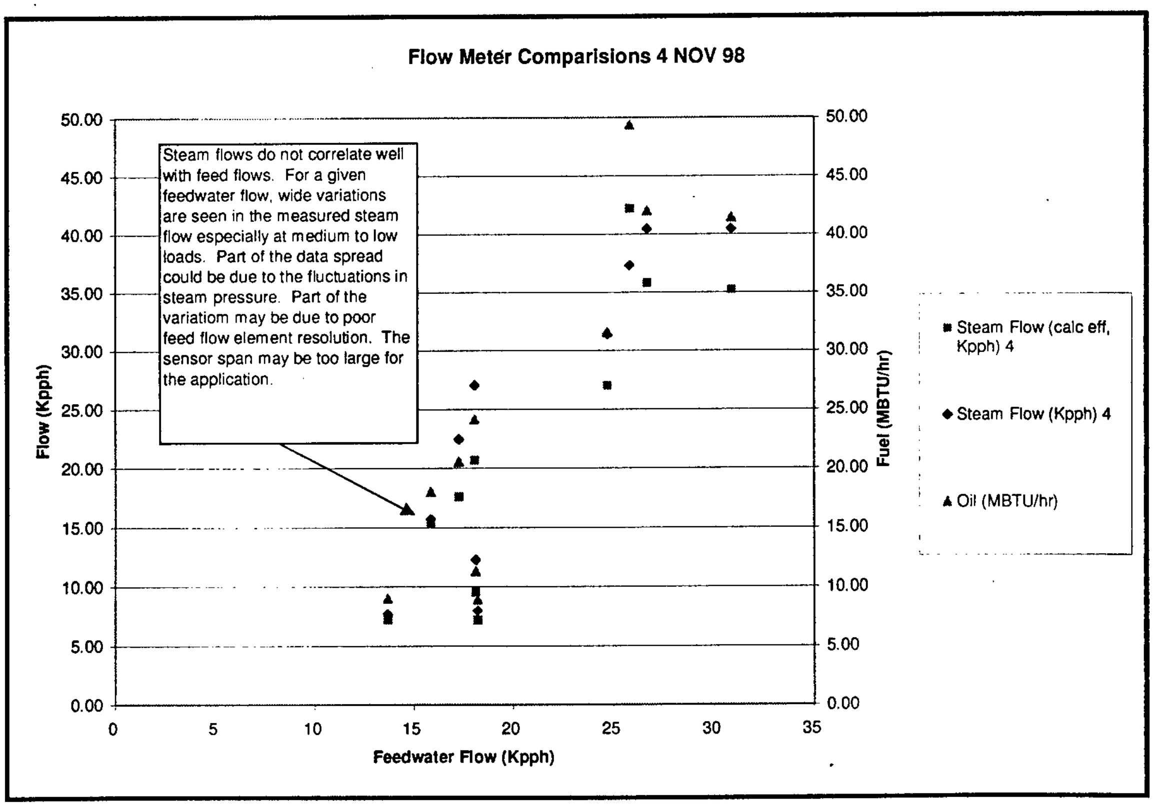
R^2 = 0.9941
Discontinuity in data due to hysterisis as load test started at 50% load. Low load data still influence by heat released from refractory and boiler casing.
Although gas flow and steam flow do not agree in magnitude, the instruments correlate well proportionally.
Flow (Kpph)
Fuel (MBTU/hr)
Steam Flow (calculated Kpph)
Steam Flow (Kpph) 3
Feedwater Flow (Kpph)
Steam Flow (calc eff Kpph) 3
Gas (MBTU/hr)
Linear (Steam Flow (Kpph) 3)


Oxygen versus Load Set Point, Boiler #4, 4 NOV 98
Oxygen (%)
Boiler Outlet CO (ppm)
Load Set Point (%)
O2 levels correctly trend lower at higher loads. However, there is room to reduce O2 levels further. Data suggests boiler needs retuning on #2 oil.
Installed Sensor (wet)
Boiler Outlet (dry)
Economizer Outlet (dry)
Roof Duct (dry)
CO (ppm)


Boiler Production versus Load Set Point, Boiler #4, 3 NOV 98
Thousand lbs/hr
Fuel (MBUT/h)
Load Set Point (%)
Boiler controls on gas not able to reach full load. May be limited by gas valve or control setpoint.
Discontinuity in data due to hysterisis as load test started at 50% load. Low load data still influence by heat released from refractory and boiler casing.
Gas valve and steam flow disagree by as much as 40%. Recalibration needed.
Steam Flow (Kpph) 3
Steam Flow (calc eff Kpph) 3
Feedwater Flow (Kpph)
Gas (MBTU/hr)


Flow Meter Comparisions 4 NOV 98
Data spread near full load is partly due to boiler not being at complete thermal equilibrium. It might take up to 3 hours per test point to get complete equilibrium.
Flow (Kpph)
Fuel (MBTU/hr)
Steam Flow (calculated Kpph)
Steam Flow (Kpph) 4
Feedwater Flow (Kpph)
Steam Flow (calc eff, Kpph) 4
Oil (MBTU/hr)


Flow Meter Comparisions 4 NOV 98
Steam flows do not correlate well with feed flows. For a given feedwater flow, wide variations are seen in the measured steam flow especially at medium to low loads. Part of the data spread could be due to the fluctuations in steam pressure. Part of the variatiom may be due to poor feed flow element resolution. The sensor span may be too large for the application.
Flow (Kpph)
Fuel (MBTU/hr)
Feedwater Flow (Kpph)
Steam Flow (calc eff, Kpph) 4
Steam Flow (Kpph) 4
Oil (MBTU/hr)

Appendix B: Excerpt from COE CEGS 15561

2.7.4.2 Air Flow Element

Air flow piezometer rings shall be provided at the inlets to the FD fan or an air foil or venturi section in the ductwork from the FD fan to the windbox.

3.5.1.3 Efficiency and Operating Tests

Upon completion, and prior to acceptance of the work, the boiler plant shall be subjected to such operating tests as may be required to demonstrate satisfactory functional operation. Each operating test shall be conducted at such times as the Contracting Officer may direct. An efficiency and capacity test shall be run on one boiler of each size installed, conducted in strict accordance with ASME PTC 4.1, abbreviated efficiency test. Measuring devices used for measuring the feedwater evaporated and the amount of fuel burned shall be properly calibrated prior to the tests. Water meter used in the test shall be suitable for hot water. Instruments, test equipment, test personnel, and fuel oil required to properly conduct tests shall be provided by the Contractor at no additional cost to the Government. The necessary natural gas, water and electricity shall be obtained as specified in the SPECIAL CLAUSES. When fuel oil is required for testing, the Contractor shall provide a minimum of [_____] liters (gallons) of No. [_____] fuel oil. Performance test shall in each case cover a period of not less than that given in the table below. The efficiency and general performance tests on the boilers shall be conducted by a qualified test engineer furnished by the Contractor. The Contracting Officer will observe and approve all tests.

TESTING AND PERFORMANCE

	Percent of Capacity		
Time	**Waterwall Watertube Boilers**	**Cylindrical Furnace Firetube Boilers**	**Firebox Boilers**
First 1 hour	50	50	50
Next 2 hours	75	75	75
Next 4 hours	100	100	100

Note: The efficiency tests may be conducted concurrently with the operating tests or separately. Thermal efficiency shall be not less than 81 percent at specified capacity for field erected boilers. Efficiencies for packaged boilers shall be as specified in Military Specifications. Maximum moisture content of saturated steam leaving the boiler shall be as specified. Testing apparatus shall be set up, calibrated, tested, and ready for testing the boiler prior to the test. Calibration curves or test results furnished by an independent testing laboratory of each instrument, meter, gauge, and thermometer to be used in the efficiency and capacity test shall be furnished prior to the test. A test report including logs, heat balance calculations, and tabulated results together with conclusions shall be delivered to the Contracting Officer in quadruplicate. An analysis by an independent testing laboratory of the fuel being burned on the test shall be submitted to the Contracting Officer. The analysis shall include pertinent data tabulated in ASME PTC 4.1, abbreviated efficiency test.

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